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Energy from the West

Impact Analysis Report Volume I. Introduction and Summary

Interagency Energy/Environment R&D Program Report

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This document reports the results of impact analyses conducted as a part of a three-year technology assessment of the development of six energy resources (coal, geothermal, natural gas, oil, oil shale and uranium) in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah and Wyoming) during the period 1975-2000. Volume I describes the purpose and conduct of the study and summarizes both site-specific and regional impact analysis results. In Volume II, more detailed analytical results are presented. Six chapters report on the analysis of the likely impacts of deploying typical energy resource development technologies at sites representative of the kinds of conditions likely to be encountered in the eight-state study area. A seventh chapter describes other local impacts which might occur; and a final chapter reports the results of regional impacts.

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Volume I: Introduction and Summary

By
Science and Public Policy Program
University of Oklahoma

Irvin L. White
Michael A. Chartock
R. Leon Leonard
Steven C. Ballard
Martha W. Gilliland
Edward J. Malecki
Edward B. Rappaport
Frank J. Calzonetti
Mark S. Eckert
Timothy A. Hall
Gary D. Miller
Michael D. Devine

Managers, Impact Analysis Report
R. Leon Leonard, Science and Public Policy
University of Oklahoma
Martha W. Gilliland, Energy Policy Studies, Inc.

C. Patrick Bartosh
B. Russ Eppright
Thomas W. Grimshaw
Milton Owen
Ken Choffel
Timothy J. Wolterink
Jim Sherman
James L. Machin
Dennis D. Harner
David Cabe
Sam A. Gavande
W. F. Holland
Carl-Heinz Michelis
Michael W. Hooper

Prepared for:
Office of Research and Development
U.S. Environmental Protection Agency
Washington, D.C. 10460

Project Officer:
Steven E. Plotkin
Office of Energy, Minerals and Industry

Contract Number 68-01-1916

Energy
from
the
West

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FORWARD

The production of electricity and fossil fuels inevitably impacts Man and his environment. The nature of these impacts must be thoroughly understood if balanced judgements concerning future energy development in the United States are to be made. The Office of Energy, Minerals and Industry (OEMI), in its role as coordinator of the Federal Energy/Environment Research and Development Program, is responsible for producing the information on health and ecological effects - and methods for mitigating the adverse effects - that is critical to developing the Nation's environmental and energy policy. OEMI's Integrated Assessment Program combines the results of research projects within the Energy/Environment Program with research on the socioeconomic and political/institutional aspects of energy development, and conducts policy - oriented studies to identify the tradeoffs among alternative energy technologies, development patterns, and impact mitigation measures.

The Integrated Assessment Program has supported several "technology assessments" in fulfilling its mission. Assessments have been supported which explore the impact of future energy development on both a nationwide and a regional scale. Current assessments include national assessments of future development of the electric utility industry and of advanced coal technologies (such as fluidized bed combustion). Also, the Program is conducting assessments concerned with multiple-resource development in two "energy resource areas":

- Western coal states
- Lower Ohio River Basin

This report, which describes the impacts likely to be experienced when six energy resources are developed in eight western states, is one of three major reports produced by the "Technology Assessment of Western Energy Resource Development" study. (The other two reports describe the technologies likely to be used and analyze policy problems and issues that can be expected to arise.) The report is divided into two volumes. The first or summary volume introduces the study, describes the development alternatives which were assessed and summarizes the results of the impact analyses which were conducted. The second volume reports the detailed results of both site-specific and regional impact analyses. The report has been designed to be useful to laypersons as well as persons who have a professional interest in energy resource development. And results are presented in a way which make this report a useful planning handbook for both professional planners and interested citizens.

We would like to receive your comments concerning this report. Such comments will help us to improve the usefulness of the products produced by our Integrated Assessment Program.

Steven Reznek

Steven R. Reznek

Acting Deputy Assistant
Administrator for Energy,
Minerals and Industry

PREFACE

This Impact Analysis Report has been prepared as part of "A Technology Assessment of Western Energy Resource Development" being conducted by an interdisciplinary research team from the Science and Public Policy Program (S&PP) of the University of Oklahoma for the Office of Energy, Minerals and Industry (OEMI), Office of Research and Development (ORD), U.S. Environmental Protection Agency (EPA). This study is one of several conducted under the Integrated Assessment Program established by OEMI in 1975. Recommended by an interagency task force, the purpose of the Program is to identify economically, environmentally, and socially acceptable energy development alternatives. The overall purposes of this particular study were to identify and analyze a broad range of consequences of energy resource development in the western U.S. and to evaluate and compare alternative courses of action for dealing with the problems and issues either raised or likely to be raised by development of these resources.

The Project Director was Irvin L.(Jack) White, Assistant Director of S&PP and Professor of Political Science, at the University of Oklahoma. White is now Special Assistant to Dr. Stephen J. Gage, EPA's Assistant Administrator for Research and Development. Michael D. Devine, now Project Director, supervised the final stages of producing this report.

R. Leon Leonard and Martha W. Gilliland have had primary management responsibility for producing this report. Leonard, now a Senior Scientist with the Radian Corporation in Austin, Texas, was a Co-Director of the research team, Associate Professor of Aeronautical, Mechanical, and Nuclear Engineering and a Research Fellow in S&PP while the study was being conducted. Gilliland is Executive Director of Energy Policy Studies, Inc., El Paso, Texas.

Steven E. Plotkin, now with the Office of Technology Assessment, was the EPA Project Officer.

Other S&PP team members are: Michael A. Chartock, a Co-Director of the research team and Associate Professor of Ecology; Steven C. Ballard, Assistant Professor of Political Science; Edward J. Malecki, Assistant Professor of Geography; Edward B. Rappaport, Visiting Assistant Professor of Geography; Frank J. Calzonetti, Research Associate in S&PP; Timothy A. Hall, Research Associate in S&PP; Gary D. Miller, Graduate Research Assistant (Civil Engineering and Environmental Science); Mark S. Eckert, Graduate Research Assistant (Geography); Dipak Kumar Sinha, Graduate Research Assistant (Aeronautical, Mechanical and Nuclear Engineering); and Michael E. Vanderpool, Graduate Research Assistant (Aeronautical, Mechanical, and Nuclear Engineering). Professors Ballard, Devine, Malecki, and Rappaport are also Research Fellows in S&PP.

Radian Corporation, Austin, Texas, has been a major contributor to this impact analysis report. C. Patrick Bartosh, Program Manager, has directed the Radian effort. Radian Personnel who contributed to the study are: B. Russ Eppright, Thomas W. Grimshaw, Milton Owen, Ken Choffel, Timothy J. Wolterink, Jim Sherman, James L. Machin, Dennis D. Harver, David Cabe, Sam A. Gavande, W.F. Holland, Carl Heinz Michelis, and Michael W. Hooper.

Water Purification Associates, Cambridge, Massachusetts, conducted a study of water requirements for steam-electric power generation and synthetic fuel plants; and the Center for Advanced Computation, the University of Illinois at Urbana-Champaign conducted a study of route specific costs comparisons of alternative transportation modes. Results of both studies have contributed to this report.

Several persons no longer with S&PP or Radian participated in the early stages of the research upon which this report is based. Three are now in graduate school at other universities: Cary N. Bloyd at Carnegie-Mellon University, Lori L. Serbin at Ohio University, and Patrick Kangas at the University of Florida. Gerald M. Clancy, William D. Conine and E. Douglas Sethness, Jr., have moved from Radian to other corporate positions.

ABSTRACT

This is the final impact analysis report of a three-year technology assessment of the development of six energy resources (coal, geothermal, natural gas, oil, oil shale, and uranium) in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, Wyoming) during the period from the present to the year 2000. Volume I describes the purpose of the study and summarizes the results and conclusions of the analysis. In Volume II, more detailed analytical results are presented. Six chapters report on the analysis of site-specific impacts of deploying typical energy resource development technologies at sites representative of the kinds of conditions likely to be encountered in the eight-state study area. A seventh chapter of Volume II identifies localized impacts, which do not differ significantly from site to site. A last chapter focuses on regional impacts likely to occur across the eight states if energy resources are developed at two different levels from the present to the year 2000. In addition to these two volumes of the Impact Analysis Report, the Policy Analysis Report and the Energy Resource Development Systems Report are published separately.

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ENERGY FROM THE WEST: IMPACT ANALYSIS REPORT

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LIST OF ACRONYMS AND ABBREVIATIONS

AC	alternating current
acre-ft	acre-feet
acre-ft/yr	acre-feet per year
AOG	associations of government
AsH_3	arsine
AUM	animal units per month
BACT	best available control technology
bbl	barrel(s)
bbl/day	barrel(s) per day
bcf	billion cubic feet
BIA	Bureau of Indian Affairs
BLM	Bureau of Land Management
BPT	best practicable technology
Btu	British thermal unit
Btu/bbl	British thermal units per barrel
BuRec	Bureau of Reclamation
CAA	Clean Air Act
$CaCO_3$	calcium carbonate
$CaSO_4$	calcium sulfate
cfs	cubic feet per second
CO	carbon monoxide
CO_2	carbon dioxide
dB	decibel
dBA	decibel(s) A-weighted
DC	direct current
EDA	Economic Development Administration
EHV	extra-high voltage
EPA	Environmental Protection Agency
ERDS	Energy Resource Development Systems
ESP	electrostatic precipitator
F	Fahrenheit
FDA	Food and Drug Administration
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FPC	Federal Power Commission
FWPCA	Federal Water Pollution Control Act
GACLA	Governors' Advisory Council on Local Affairs
GNP	gross national product
gpd	gallons per day
gpm	gallons per minute
HC	hydrocarbons
H_2S	hydrogen sulfide

kV	kilovolt(s)
kWh	kilowatt-hour(s)
lbs/ton	pounds per ton
LCRB	Lower Colorado River Basin
L_{dn}	day-night equivalent sound level
MESA	Mining Enforcement and Safety Administration
mg/ℓ	milligrams per liter
MMcfd	million cubic feet per day
MMgpd	million gallons per day
MMscfd	million standard cubic feet per day
MMtpy	million tons per year
MW	megawatt(s)
MWe	megawatt-electric
mph	miles per hour
NAAQS	National Ambient Air Quality Standards
NC	not calculated or not considered
NH_3	ammonia
NH_4Cl	ammonium chloride
NIOSH	National Institute of Occupational Safety and Health
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NSPS	New Source Performance Standards
OPEC	Organization of Petroleum Exporting Countries
ORV	off-road vehicle
PAH	polyaromatic hydrocarbons
pCi/g	picocuries per gram
pCi/ℓ	picocuries per liter
pH	acidity/alkalinity
ppb	parts per billion
ppm	parts per million
PSD	prevention of significant deterioration
psi	pounds per square inch
psia	pounds per square inch atmosphere
Q	10^{15} British thermal units and/or quad(s)
Ra-226	Radium 226
Rn-222	Radon 222 gas
SEAS	Strategic Environmental Assessment System
SO_2	sulfur dioxide
S&PP	Science and Public Policy Program
SRI	Stanford Research Institute
tcf	trillion cubic feet
TDS	total dissolved solids
TOSCO	The Oil Shale Corporation
tpd	tons per day
tpy	tons per year
TSP	total suspended particulates
TVA	Tennessee Valley Authority
UCRB	Upper Colorado River Basin
μg	microgram(s)

$\mu g/m^3$	micrograms per cubic meter
UMRB	Upper Missouri River Basin
U_3O_8	uranium oxide and/or yellowcake
USGS	U.S. Geological Survey
WPA	Water Purification Associates
ZDP	zero discharge of pollutants

CONVERSION TABLE

BTU CONTENT OF ENERGY FORMS

Electricity: 1 kWh = 3413 Btu.

Natural gas: 1 cubic foot = 1000 Btu.

Petroleum: 1 barrel (bbl) = 42 gallons
crude oil--1 bbl = 5.8 million Btu;
distillate fuel--1 bbl = 5.8 million Btu;
residual fuel --1 bbl = 6.3 million Btu;
gasoline--1 bbl = 5.3 million Btu;
Uranium--1 pound U_{235} = 3.6×10^{10} Btu.

1 million = 10^{6}
1 billion = 10^{9}
1 trillion = 10^{12}

1 Quad = 10^{15} Btu
1 megawatt = 10^{6} Watts
1 kilowatt = 10^{3} Watts

ENERGY

UNITS	joule	cal	Btu	kWh
1 joule	1	2.389×10^{-1}	9.48×10^{-4}	2.778×10^{-7}
1 cal	4.186	1	3.97×10^{-3}	1.163×10^{-6}
1 Btu	1.055×10^{3}	2.52×10^{2}	1	2.93×10^{-4}
1 kWh	3.6×10^{6}	8.6×10^{5}	3.413×10^{3}	1

RATE

UNITS	Cubic Meter/Year	Gallon/Minute	Acre-Feet/Year
1 gallon/minute	1.9898×10^{3}	1	1.613
1 acre-foot/year	1.2335×10^{3}	6.2×10^{-4}	1

PRESSURE

UNITS	atmospheres	kilograms/square centimeter	pounds per square inch	N/m^2, Pa
1 atmosphere	1	1.033	1.469×10^{1}	1.03×10^{5}
1 pound/sq. inch	6.804×10^{-2}	7.03×10^{-2}	1	6894.76

LENGTH

UNITS	Meters	Feet	Yards	Miles
1 meter	1	3.28	1.093	6.21×10^{-4}
1 yard	9.14×10^{-1}	3.0	1	5.68×10^{-4}
1 mile	1.609×10^{3}	5.28×10^{3}	1.76×10^{3}	1

WEIGHT

UNITS	Kilogram	Pound	Metric Ton	Ton (Short)
1 kilogram	1	2.2046	1.0×10^{-3}	1.102×10^{-3}
1 metric ton	1.0×10^{3}	2.205×10^{3}	1	1.102
1 ton (short)	9.072×10^{2}	2.0×10^{3}	9.078×10^{-1}	1

VOLUME

UNITS	Liters	Cubic Feet	Acre-Feet	Gallons
1 liter	1	3.531×10^{-2}	8.107×10^{-7}	2.642×10^{-1}
1 acre-foot	1.234×10^{6}	4.356×10^{4}	1	3.259×10^{5}
1 gallon (U.S.)	3.785	1.337×10^{-1}	3.068×10^{-6}	1

AREA

UNITS	Square Meters	Square Feet	Square Yards	Acres	Square Miles
1 square meter	1	1.076×10	1.196	2.471×10^{-4}	3.86×10^{-7}
1 square yard	8.361×10^{-1}	9.0	1	2.066×10^{-4}	3.228×10^{-7}
1 acre	4.047×10^{3}	4.35×10^{4}	4.84×10^{3}	1	1.562×10^{-3}
1 square mile	2.59×10^{6}	2.788×10^{7}	3.098	6.402×10^{2}	1

atm = atmospheres
psi = pounds per square inch
cal = calorie
N/m^2, Pa = Newton per square meter, Pascal
Btu = British thermal units
kWh = kilowatt hour

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Mr. John Bermingham
Attorney
Denver, Colorado
(formerly Regional Representative for the secretary, U.S. Department of Commerce)

Dr. Thadis W. Box
Dean
College of Environmental Studies
Utah State University
Logan, Utah

Governor Jack Campbell
President
Federation of Rocky Mountain States
Denver, Colorado

Mr. Bill Conine
Environmentalist
Energy Minerals--U.S. and Canada
Mobil Oil Corporation
Denver, Colorado

Ms. Sharon Eads
Attorney
Native American Rights Fund
Boulder, Colorado

Mr. Michael B. Enzi
Mayor
Gillette, Wyoming

Mr. Lionel S. Johns
Program Manager
Office of Technology Assessment
U.S. Congress
Washington, D.C.

Mr. Kenneth Kauffman
Chairman
Water for Energy Management Team
U.S. Department of the Interior
Engineering and Research Center
Denver, Colorado

Mr. S.P. Mathur
Division of Regional Assessment
U.S. Department of Energy
Washington, D.C.
(formerly ERDA Representative
to the Water Resources Council)

Mr. Leonard Meeker
Attorney
Center for Law and Social Policies
Washington, D.C.

Dr. Richard Meyer
ABT Associates
Anglewood, Colorado
(formerly Acting Director,
Western Governors' Energy
Policy Office)

Dr. Raphael Moure
Industrial Hygienist
Oil, Chemical, and Atomic Workers Union
Denver, Colorado

Mr. Bruce Pasternack
Booz, Allen, Hamilton
Bethesda, Maryland
(formerly Assistant Administrator, Policy and Program
Evaluation, Federal Energy
Administration, Washington,
D.C.)

Mr. Robert Richards
Kaiser Engineers
Oakland, California

Mr. H. Anthony Ruckel
Regional Lawyer
Sierra Club Legal Defense Fund
Denver, Colorado

Mr. Warren Schmechel
President and Chief Operating Officer
Western Energy Company
Butte, Montana

Mr. Vernon Valantine
Colorado River Board of California
Los Angeles, California

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Others who have contributed to specific analyses include:

Mr. Donald S. Cooper
Principal Energy Analyst
International Research and
Technology Corporation
McLean, Virginia

Dr. James M. Goodman
Associate Professor of
Geography
University of Oklahoma

Dr. Arnold G. Henderson
Professor of Architecture
University of Oklahoma

Dr. Daniel B. Kohlhepp
Assistant Professor of
Finance
University of Oklahoma

Mr. Richard Meyer
Program Manager
International Research and
Technology Corporation
McLean, Virginia

PART I: THE ENERGY FROM THE WEST STUDY

INTRODUCTION

The three chapters in this part of the report: introduce the "Energy From the West" study and describe the general context within which energy resource development in the West will occur (Chapter 1); describe the analytical structure of the study and the energy technologies considered (Chapter 2); and present a summary of the results of the analysis of impacts likely to occur when western energy resources are developed (Chapter 3).

CHAPTER 1

AN INTRODUCTION TO WESTERN ENERGY RESOURCE DEVELOPMENT

1.1 INTRODUCTION TO THE WESTERN ENERGY STUDY

This impact analysis report is a product of a three-year "Technology Assessment of Western Energy Resource Development" being conducted for the Office of Energy, Minerals and Industry, Office of Research and Development, U.S., Environmental Protection Agency. The study is being conducted by an interdisciplinary research team from the Science and Public Policy Program (S&PP), University of Oklahoma, with the assistance of two major subcontractors (Radian Corporation, Austin, Texas, and Water Purification Associates, Cambridge, Massachusetts), several other subcontractors, consultants, and an advisory committee.

The overall purpose of the study is to attempt to determine what the consequences of western energy resource development will be and how public and private policymakers might deal with them. Specific objectives are to:

- Identify and describe energy development alternatives;
- Determine and analyze impacts;
- Identify and define policy problems and issues;
- Identify, evaluate and compare alternative policies and implementation strategies;
- Identify and describe research and data needs.

The study focuses on the development of six energy resources in the eight-state area and at the six sites shown in Figure 1-1. Coal,

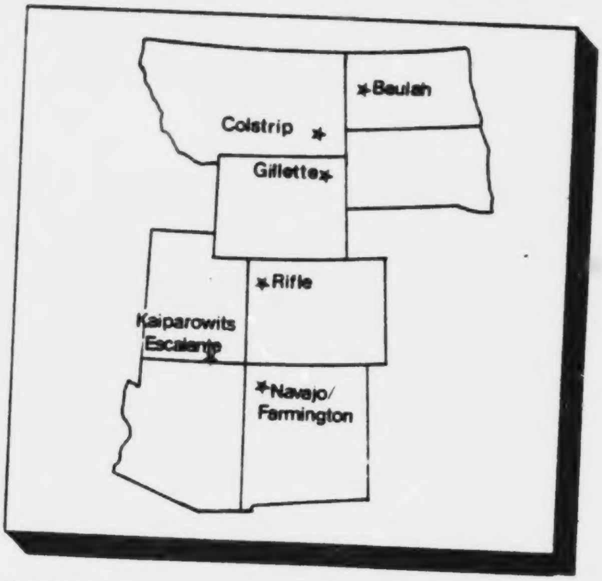

FIGURE 1-1: THE EIGHT-STATE STUDY AREA AND SIX SITES

oil shale, uranium, oil, natural gas and geothermal are the six energy resources being considered. The technological alternatives for developing these resources are listed in Table 1-1. (These alternatives are described in Chapter 2.) The time period during which the consequences of development are being assessed extends to the year 2000.

Technological alternatives and the laws and regulations which regulate and control their construction and operation are described in detail in Energy From the West: Energy Resource Development Systems.[1] An earlier progress report presented the preliminary results of an analysis of impacts likely to occur when these technologies are deployed at specific sites and to produce specified quantities of energy on a region-wide basis.[2] The problems and issues likely to arise as a consequence of this development together with the results of an analysis of alternative policies and strategies for dealing with them are reported in Energy From the West: Policy Analysis Report.[3] Two work plans or research design reports describe our interdisciplinary team approach to technology assessment as a kind of applied policy analysis, the analytical structure of the study, and the analytical

TABLE 1-1: DEVELOPMENT ALTERNATIVES[1]

Coal:
- Surface and Underground Mining
- Direct Export by Unit Train and Slurry Pipeline
- Electric Power Generation
- Gasification
- Liquefaction
- Transportation by Pipeline and EHV

Oil Shale:
- Underground Mining
- Surface Retorting
- Modified In-Situ
- Transportation by Pipeline

Uranium:
- Surface, Underground, and Solutional Mining
- Milling
- Transportation by Truck

Oil and Natural Gas:
- Conventional Drilling and Production
- Enhanced Oil Recovery
- Transportation by Pipeline

Geothermal
- Hot Water and Hot Rock
- Electric Power Generation
- Transportation by EHV

EHV = extra-high voltage

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[1] White, Irvin L., et al. Energy From the West: Energy Resource Development Systems Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

[2] White, Irvin L., et al. Energy From the West: A Progress Report of a Technology Assessment of Western Energy Resource Development, 4 vols. and Executive Summary. Washington, D.C.: U.S., Environmental Protection Agency, 1977.

[3] White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

methods and techniques we have used.[1] This report presents the final results of our impact analyses and represents an extension and refinement of the results presented in our Energy From the West progress report.

1.2 THE CONTEXT OF WESTERN ENERGY RESOURCE DEVELOPMENT[2]

As now articulated, our major national energy policy objectives are to decrease dependence on foreign energy sources and to reduce imports to a more economically acceptable level. In the short- and mid-term future, this translates into an emphasis on increasing domestic production, particularly fossil fuels. Given its substantial energy resources, the western U.S. is expected to be a major contributor to the increased production of these resources.

As noted earlier, six western energy resources are being considered in this study: coal, oil shale, uranium, oil, natural gas and geothermal. The quantity of each of these in the region is shown in Table 1-2 and their general distribution in the eight-state study area in Figure 1-2. Coal and oil shale are the most abundant of the six. In fact, approximately 36 percent of all U.S. coal is located in the study area; virtually all the nation's high grade oil shale is located in the Green River Formation in western Colorado, Utah, and Wyoming; and almost all of the nation's high grade uranium ore is located in the eight states, primarily in New Mexico and Wyoming.

As shown in Table 1-3, the federal government and Indians own almost 45 percent of the total land in the eight-state study area. Together, the federal government and Indians own more than half the land in Arizona, Utah, and Wyoming and more than a third in Colorado, Montana, and New Mexico.

Data on resource ownership are more difficult to obtain. However, it appears that the federal government owns about half the coal, geothermal, and uranium, and about 80 percent

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[1] White, Irvin L., et al. First Year Work Plan for a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1976; and White, Irvin L., et al. Work Plan for Completing a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1978.

[2] See White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming, for a more extensive description of the national and regional context of western energy resource development.

TABLE 1-2: PROVEN RESERVES OF SIX ENERGY RESOURCES IN THE EIGHT-STATE STUDY AREA

RESOURCE	WESTERN RESERVES (10^{15} Btu's)	PERCENT OF U.S. TOTAL RESERVES
Coal[a]	3430.0	35.9
Crude Oil[b]	12.2	6.4
Natural Gas[c]	19.9	7.8
Oil Shale[d]	464.0	≈100.0
Uranium[e]	246.6	90.6
Geothermal[f]	650.0	22.1

≈ = approximately

[a] Hamilton, Patrick A., D.H. White, Jr., and Thomas K. Matson. The Reserve Base of U.S. Coals by Sulfur Content, Part 2: The Western States, Information Circular 8693. Washington, D.C.: U.S., Department of the Interior, Bureau of Mines, 1975, p. 7 and Table D, pp. 282-322; and Parker, N.A., and B.C. Thompson. U.S. Coal Resources and Reserves. Washington, D.C.: U.S., Federal Energy Administration, 1976, p. 3. Reserves include identified coal resources that can be economically and legally mined at the time of determination. For conversion to British thermal units (Btu's) the national average heat content was assumed to be 11,000 Btu's per pound of coal (calculated from data in U.S., Congress, House of Representatives, Committee on Science and Technology, Subcommittee on Energy Research, Development, and Demonstration. Energy Facts II, Committee Print, by Library of Congress, Congressional Research Service, Science Policy Research Division. Washington, D.C.: Government Printing Office, 1975) and the eight-state average heat content was assumed to be 8,500 Btu's per pound (Cazalit, Edward, et al. A Western Regional Energy Development Study: Economics. Menlo Park, Calif.: Stanford Research Institute, 1976, Vol. II, p. X-26).

[b] Bureau of National Affairs. "Proved Crude Oil Reserves: American Petroleum Institute, Data for 1976." Energy Users' Report, Reference File, p. 81:0623 (September 29, 1977). Reserves include economically recoverable petroleum in identified geologic deposits. A heat content of 5.8 million Btu's per barrel of oil was assumed (U.S., Library of Congress, Congressional Research Service. In Bureau of National Affairs. "Energy Conversion Factors. Energy Users' Report, Reference File, p. 01:0062 [November 28, 1974]).

[c] Bureau of National Affairs. "Estimated Total Proved Reserves of Natural Gas in the U.S. (statistical tables were provided by the American Gas Association and released in April 1977)." Energy Users' Report, Reference File, p. 81:0601 (September 29, 1977). Reserves include economically recoverable natural gas in identified reservoirs. A heat content of 1,000 Btu's per cubic foot of gas was assumed (U.S., Library of Congress, Congressional Research Service. In Bureau of National Affairs. "Energy Conversion Factors," Reference File, p. 01:0062 [November 28, 1974]).

TABLE 1-2: (Continued)

[d] U.S., Congress, Senate, Committee on Energy and Natural Resources, Subcommittee on Energy Research and Development. Petroleum Industry Involvement in Alternative Sources of Energy, Committee Print. Washington, D.C.: Government Printing Office, 1977, pp. 154 and 169. Reserves include only known high-grade (25-100 gallons per ton) reserves recoverable under present conditions. It was assumed that shale oil is equivalent to crude oil in heat content; and 5.8 million Btu's per barrel was used as the basis for conversion.

[e] U.S., Energy Research and Development Administration, Grand Junction Office. Statistical Data of the Uranium Industry, GJO-100(77). Grand Junction, Colo.: Energy Research and Development Administration, 1977, p. 61. Reserves include known uranium deposits which can be exploited at a cost of $30 per pound of uranium oxide (U_3O_8) or less. Latest cost estimates indicate, however, that $50 per pound is a more likely cost figure. The heat content was evaluated in relationship to the lightwater reactor and was assumed to be four hundred billion Btu's per ton of U_3O_8 (U.S., Congress, House of Representatives, Committee on Science and Technology, Subcommittee on Energy Research, Development, and Demonstration. Energy Facts II, Committee Print, by Library of Congress, Congressional Research Service, Science Policy Research Division, 1975, p. 24).

[f] Renner, J.L., D.E. White, and D.L. Williams. "Hydrothermal Convection Systems," in White, D.E., and D.L. Williams, eds. Assessment of Geothermal Resources of the United States--1975, Geological Survey Circular 726. Reston, Va.: U.S., Department of the Interior, Geological Survey, 1975. Resources include not only reserves (identified sources), but also submarginal (recoverable only at a cost that is more than twice the current price of competitive energy systems) and paramarginal (recoverable at between one and two times the current price of competitive energy) resources in identified hydrothermal convection systems. In addition, an estimated 260,000 X 10^{15} Btu's of hot dry rock geothermal resources may be economically exploitable in the U.S. No estimate has yet been made of the amount of hot dry rock resources in the eight-state area. (See Los Alamos Scientific Laboratory, HDR Project Staff. Hot Dry Rock Geothermal Energy Development Project, Annual Report, Fiscal Year 1977. Washington, D.C.: U.S., Department of Energy, 1978, p. 19.) For conversion to Btu's from calories, it was assumed that 10^{18} calories was equivalent to the heat of combustion of ≈690 million barrels of petroleum or ≈154 million short tons of coal. (See White, D.E., and D.L. Williams. "Summary and Conclusions," in White and Williams. Geothermal Resources, p. 148.)

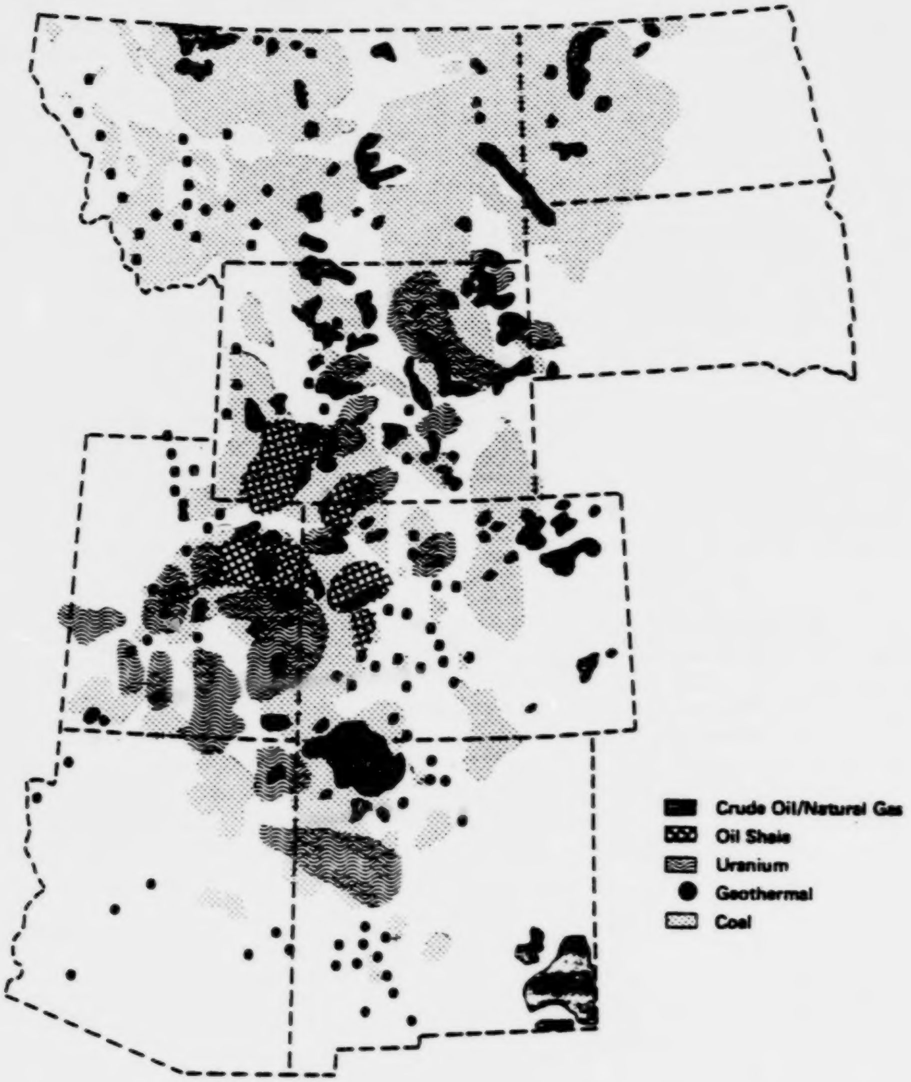
Crude Oil/Natural Gas
Oil Shale
Uranium
Geothermal
Coal

FIGURE 1-2: GENERAL DISTRIBUTION OF COAL, CRUDE OIL/NATURAL GAS, GEOTHERMAL, OIL SHALE, AND URANIUM RESOURCES IN EIGHT WESTERN STATES

TABLE 1-3: FEDERAL AND INDIAN LANDS IN THE EIGHT-STATE STUDY AREA

STATE	TOTAL AREA (Thousands of Acres)	PERCENT FEDERAL	PERCENT INDIAN	PERCENT FEDERAL AND INDIAN
Arizona	72,688	44	30	74
Utah	52,697	66	7	73
Wyoming	62,343	48	3	51
New Mexico	77,766	33	8	41
Colorado	66,486	36	1	37
Montana	93,271	30	6	36
South Dakota	48,882	7	12	19
North Dakota	44,452	5	5	10
Total	518,585	35	9	44

Sources: U.S., Department of the Interior, Bureau of Land Management. Public Land Statistics 1976. Washington, D.C.: Government Printing Office, 1977, p. 10; and U.S., Department of Commerce. Federal and State Indian Reservations and Indian Trust Areas. Washington, D.C.: Government Printing Office, 1974.

of the oil shale resources in the eight-state area. The 271 Indian reservations in the U.S. are estimated to contain from 10 to 16 percent of the nation's coal reserves and one-third of all lands held for uranium exploration and development. Most of these resources are located on a few of the approximately 50 Indian reservations located in our study area.[1] For example, Indian lands in Colorado, New Mexico, and Wyoming account for 45 percent of all lands held for uranium exploration and development. Over 85 percent of the nation's proven uranium reserves are located in these three states.[2]

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[1] See U.S., Federal Trade Commission, Bureau of Competition. Report to the Federal Trade Commission on Mineral Leasing on Indian Lands. Washington, D.C.: Federal Trade Commission, 1975.

[2] Bendix Field Engineering Corp. Survey of Lands Held for Uranium Exploration, Development and Production in Fourteen Western States in the Six Month Period Ending December 31, 1976, GJBX-33(77). Grand Junction, Colo.: U.S., Energy Research and Development Administration, 1977, p. 1; and U.S., Energy Research and Development Administration, Grand Junction Office. Statistical Data of the Uranium Industry, GJO-100(77). Grand Junction, Colo.: Energy Research and Development Administration, 1977, p. 61.

Coal production in the study area exceeded 115 million tons in 1975, more than 85 percent of which was surface-mined.[1] In addition to being low in sulfur content, many western coals occur in thick seams near the surface, which also enhances the attractiveness of these coals to developers. As a result, the number of surface coal mines in the West has increased during the past five years, while the number of underground mines has remained relatively unchanged.

Demonstrated oil shale reserves in the study area are estimated at 464 billion barrels (bbl).[2] As with coal, the federal government owns the major share of this resource.[3] However, unlike coal, no commercial oil shale production has yet taken place. In spite of the large quantity of oil shale resources, difficulties in planning, mining, and efficiently and economically converting the resource to a usable fuel have restrained development.[4]

Although highly dependent on ore quality and recoverability, uranium reserves in the study area are estimated to be above 600 thousand tons of yellowcake.[5] Large uncertainties surround the availability of uranium resources, most of which are located in northwestern New Mexico and in Wyoming. Subsurface mineral rights for about two-thirds of the lands thought to contain significant uranium resources are held by the federal government. In 1975, 11 thousand tons of yellowcake were produced in the area. This represented more than 90 percent of total U.S. production.

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[1] U.S., Federal Energy Administration. 1977 National Energy Outlook, Draft. Washington, D.C.: Federal Energy Administration, January 15, 1977, Vol. 1, p. 23.

[2] University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Washington, D.C.: Government Printing Office, 1975, pp. 2-7. This total represents only reserves of the highest quality category. This is virtually all of the nation's demonstrated oil shale reserves.

[3] Some ownership is in dispute and will probably have to be determined by the courts.

[4] Science and Public Policy. Energy Alternatives. Chapter 2. Oil shale has been developed in other countries.

[5] U.S., Energy Research and Development Administration, Grand Junction Office. Statistical Data of the Uranium Industry, GJO-100(77). Grand Junction, Colo.: Energy Research and Development Administration, 1977, p. 61.

Oil production from the West in 1976 was about 214 million bbl, a large percentage of the remaining proved western reserves of 2.1 billion bbl.[1] Gas production in the West was about 1.8 trillion cubic feet (tcf) in 1976 or almost 10 percent of the remaining reserves of 19.8 tcf. At current consumption rates, this quantity of gas would meet national needs for a single year.[2]

Although none of the Rocky Mountain and Great Plains states is using geothermal energy commercially, exploration and experimental development are taking place in several locations. Resources have not been accurately characterized, and estimates vary from as little as one thousand megawatts-electric (MWe)[3] of recoverable generating capacity to as high as 150 million MWe for the entire West.[4] Recent estimates of western reserves suggest an electrical capacity of 43 thousand MWe, and most of these resources are owned by the federal government.[5]

The actual pattern and development rates of the western energy resources described above will be contingent on a wide range of economic, social, and political factors such as energy demand, price, availability of development capital, availability of raw materials and skilled manpower, environmental policies and regulations, competing land uses, and attitudes toward development. Thus, although not the focus of this study, identification of some of these factors is important to understanding the context within which western energy development is and will continue to take place.[1]

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[1] Bureau of National Affairs. Energy Users Report, Reference File, R81:0623, (September 28, 1977).

[2] Ibid., p. 81: 0601.

[3] A megawatt-electric is one million watts (one thousand kilowatts) and is a standard measure of the amount of power, as electricity, that can be produced by a facility at any one time.

[4] Muffler, L.D.P., and D.E. White. Geothermal Energy Resources of the U.S., Geological Survey Circular 650. Washington, D.C.: Government Printing Office, 1972, p. 10; and Rex, Robert W., and David J. Howell. "Assessment of U.S. Geothermal Resources," in Kruger, Paul, and Carel Otte, eds. Geothermal Energy: Resources, Production, and Stimulation. Stanford, Calif.: Stanford University Press, 1973, p. 63.

[5] Assuming a conversion efficiency of ten percent, a reservoir lifetime of fifty years and reserve estimates as reported in Table 1-2.

Energy demand is affected by (among other things) price, availability, level of economic activity, and public perceptions. Demand projections indicate increases, although at lower growth rates than in the past.[2] However, the demand for electricity is expected to continue to grow at a rate almost twice as fast as overall energy demand, and a gradual shift from the use of oil and gas to coal and nuclear materials for generating electricity is expected.[3]

The price of oil has largely been a product of the current seller's market in petroleum created by worldwide increases in oil consumption, decreasing production in consuming nations, and a greater ability of producing nations to act in concert. The Organization of Petroleum Exporting Countries (OPEC) has now gained control over the majority of oil producing operations and effectively determines the price of oil and, thereby, the price of many other energy resources.[4]

Recent oil price increases have made coal and uranium more economically attractive fuels and have stimulated interest in oil shale and geothermal resources, as well as in enhanced recovery of domestic oil. For example, the U.S. and several other countries have greatly increased their coal exports in recent years.[1] However, importing uranium for domestic use has been prohibited since the mid-1960's.[2] Although this policy has resulted in relatively high U.S. uranium prices, it has also provided stability for uranium mining operations in the Rocky Mountains and the Northern Great Plains.[3]

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[1] These factors are discussed in Chapters 1 and 2 of White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

[2] The demand for energy has increased at a rate of about 7 percent per year over the past decade. During the past 2 years however, U.S. energy demand has actually diminished, from 74 quadrillion British thermal units (Btu's) per year in 1973 to 71 quadrillion Btu's by the end of 1975. See U.S., Federal Energy Administration. "Overview." Monthly Energy Review, March 1976, p. 13. The 1976 figures show that demand for energy was back up to over 74 quadrillion Btu's; 1977 demand was over 75 quadrillion Btu's. For the 1976 and 1977 estimates see U.S., Federal Energy Administration. "Overview." Monthly Energy Review, May 1978, p. 8.

[3] The price of OPEC oil varied from $1.89 to $2.00 per bbl between 1955 and 1970. In January 1972, the price was $2.18; in October 1973, it rose to $5.12. In January 1976, following the October embargo, OPEC oil was $11.65. In January 1976, the price was about $14.00 per bbl. In January 1978 OPEC oil was approximately $14.30 per bbl.

While high energy prices have stimulated new interest in western energy resources, there is no guarantee that prices will remain high. As noted, energy prices are being supported through the efforts of an international cartel, OPEC, and do not directly reflect production costs. Future decreases in price are quite possible, leading investors to be wary of investing in new projects (such as coal gasification), even though such projects might appear to be profitable at current prices. Risk factors such as these may significantly impede the availability of capital for certain kinds of western energy resource development.

The availability of raw materials, manpower, and equipment will also help to determine development schedules and production rates for western energy resource development. For example, many resource-rich sections of the study area have marginal water supplies. Thus, meeting the water needs of large-scale energy developments could result in inadequate water supplies for some users.

Large and/or rapid resource developments can be constrained by available skilled manpower pools and equipment problems. These problems might range from a shortage of mining engineers to the questionable ability of industry to meet the short-term need for large numbers of specialized pieces of equipment (such as draglines and high-pressure vessels for gasification and liquefaction facilities).

A wide range of environmental and social factors will also influence decisions to develop western U.S. energy resources. For example, environmental quality has been described as both a major reason for and a potential obstacle to development in the region. Low-sulfur western coal has been an attractive substitute for more polluting fuels.[1] Conversely, the "Big Sky" of the Northern Great Plains and the undisturbed vistas of the Rocky Mountains and canyonlands are widely recognized as national resources. In fact, the Congress has enacted legislation intended to maintain or improve the quality of such resources by, for example, establishing prevention of significant deterioration standards for air.[2]

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[1] In contrast to oil, trade in coal has been based on bilateral agreements between private purchasers and producers.

[2] Yager, Joseph A., and Eleanor B. Steinberg. Energy and U.S. Foreign Policy, a report to the Energy Policy Project of the Ford Foundation. Cambridge, Mass.: Ballinger, 1974, p. 21.

[3] Ibid.

Western attitudes toward energy development also help to set the context of western energy resource development. It is difficult to generalize about westerner's attitudes. Environmental quality, scenic beauty, and present lifestyle are obviously widely held values. But so are higher personal incomes, more job opportunities, more amenities, easier access to medical services, and a variety of other benefits associated with energy resource development. Both kinds of values can be and apparently often are held by the same person. Since these values are often in conflict, it is difficult for westerners both individually and collectively to be consistent in expressing their attitudes toward energy development.

However, there do seem to be several consistent themes among westerners. For example, outside the large metropolitan areas there is a general opposition to the intervention of outsiders whether the intervener be the federal government or the Sierra Club. Westerners generally seem to believe that they should be the ones to decide their futures; for example, public officials in southern Utah believe they should decide whether maintaining 75-mile visibility is more or less highly valued than the anticipated economic and fiscal benefits of energy resource development.[3]

The actual level of western energy resource development, where development will take place, and what technologies are used to develop it will be determined by these and numerous other factors, national and state energy policies, and other considerations. The brief discussion here is intended to provide only a very general introduction to the context within which development is and will be taking place. A more extended discussion is presented in Chapters 1 and 2 of the Energy From the West policy analysis report.[1]

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[1] However, the 1977 Clean Air Act Amendments require "best available control technology" be used regardless of the sulfur content of the coal, thus lessening, perhaps eliminating, the advantage low sulfur coal has had. Clean Air Act Amendments of 1977, Pub. L. 95-95, 91 Stat. 685.

[2] Ibid.

[3] This is the position strongly expressed to members of the S&PP Research Team who visited the area.

1.3 ORGANIZATION OF THIS REPORT

The two remaining chapters in Part I describe the development alternatives being assessed and summarize our impact analysis findings. Six of the eight chapters in Part II report the results of impact analyses for our site-specific scenarios: Colstrip, Montana; Beulah, North Dakota; Gillette, Wyoming; Rifle, Colorado; Kaiparowits/Escalante, Utah; and Navajo/Farmington, New Mexico. The seventh chapter in Part II, Chapter 10, discusses local impacts which either do not differ significantly from site to site or which cannot be dealt with on a site-specific basis because so little is known about them. The final chapter in Part II reports the results of our aggregate analyses of impacts in the eight-state study area.

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[1] White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

CHAPTER 2

STRUCTURE OF THE STUDY

2.1 INTRODUCTION

As indicated briefly in Chapter 1, this study of western energy resource development focuses on the development of six resources in eight western states. This chapter describes the conceptual framework used to structure the study, the site-specific and regional scenarios analyzed, and the technologies examined.

2.2 CONCEPTUAL FRAMEWORK

The conceptual framework used in this technology assessment is shown in Figure 2-1. This systems diagram shows that impacts are a product of the interaction of a technology and "existing conditions." When sited, constructed, and operated, a technology creates input demands, such as for land, water, capital, labor, and services, and produces outputs, including a product such as electricity, and residuals or byproducts such as air and water pollutants. These inputs and outputs interact with the existing social and physical environment to produce impacts. The existing conditions include such things as the availability and current uses of water, meteorological conditions, the capacity of existing community services and facilities, the economy, and current siting and air quality policies and regulations. Impacts[1] include such things as changes in ambient air quality, the availability of housing, employment opportunities, and tax revenues. Impacts can be either costs or benefits.

The systems diagram in Figure 2-1 shows that, on the basis of individual and/or group perceptions, some of these impacts are identified as problems and issues which policymakers, both public and private, must attempt to resolve. In choosing among the range of available responses, policymakers are limited by a variety of economic, legal, technological, social, and other constraints.

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[1] The term impact is not a pejorative as used in this study. It includes effects which can be defined as either benefits or costs.

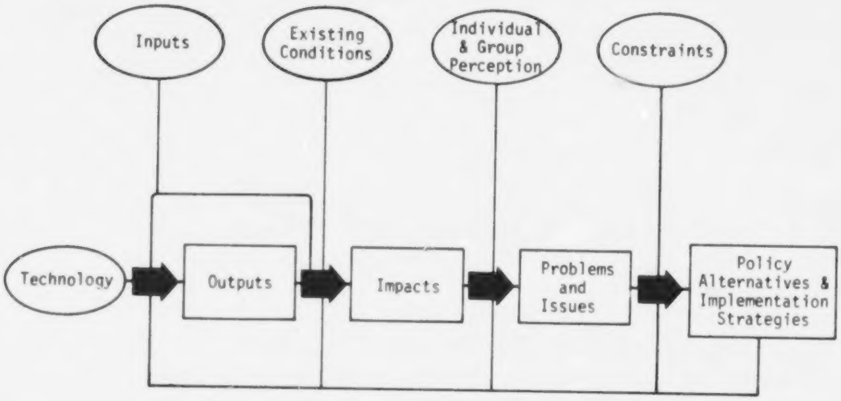

FIGURE 2-1: A CONCEPTUAL FRAMEWORK FOR ASSESSING PHYSICAL TECHNOLOGIES

A more detailed description of this conceptual framework and how it has been applied in this study is presented in our First Year Work Plan for a Technology Assessment of Western Energy Resource Development.[1] The brief description here is limited to showing why we structured the study as we did. This structure is described in the following section.

2.3 THE SCENARIOS

Seven energy resource development scenarios were used to organize various combinations of energy resource development alternatives and levels of development between 1975 and the year 2000, and to structure the impact analyses described in this report. Six of these scenarios are site-specific and combine typical energy development technologies and sites representative of the range of existing conditions found in the study area. The seventh scenario specifies two levels of development for the entire study area and the combinations of technologies and resources used to produce these quantities of energy.

Table 2-1 identifies the six sites selected and lists the hypothetical energy developments considered and the development schedule for each site. As the table shows, several process mixes, development schedules, and levels of development have been included in the scenarios. Our objective was to analyze a variety of technology and location combinations as a basis for

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[1] White, Irvin L., et al. First Year Work Plan for a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1976.

TABLE 2-1: SITE-SPECIFIC ENERGY DEVELOPMENTS[a]

SITE	HYPOTHETICAL ENERGY DEVELOPMENT	ON-LINE
Kaiparowits/ Escalante	Coal Underground/Electrical Generation/Transmission (3,000 MWe)	1983
	Coal Underground/Electrical Generation/Transmission (3,000 MWe)	1987
Navajo/ Farmington	Coal Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1985
	Coal Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1980
	Coal Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1990
	Coal Surface Mine/Synthoil Liquefaction/Pipeline (100,000 bbl/day)	2000
	Uranium Underground Mine/Milling/Truck (1,000 metric tons yellowcake per year)	1985
Rifle	Oil Shale Underground Mine/TOSCO II Retorting/Upgrading/Pipeline (50,000 bbl/day)	1985
	Oil Shale Modified In Situ Retorting/Upgrading/Pipeline (57,000 bbl/day)	1990
	Coal Underground Mine/Electrical Generation/Transmission (1,000 MWe)	1980
	Oil Wells/Pipeline (400 wells, 50,000 bbl/day)	1985
Gillette	Coal Surface Mine/Rail Transport (25 MMtpy)	1980
	Coal Surface Mine/Slurry Pipeline (25 MMtpy)	1985
	Coal Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1985
	Coal Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1985
	Coal Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1995
	Coal Surface Mine/Synthoil Liquefaction/Pipeline (100,000 bbl/day)	2000
	Gas Wells/Beneficiation/Pipeline (83 wells, 250 MMcfd)	1979

TABLE 2-1: (Continued)

SITE	HYPOTHETICAL ENERGY DEVELOPMENT	ON-LINE
Gillette (Continued)	Uranium Surface Mine/Milling/Truck (1,000 metric tons yellowcake per year)	1985
	Uranium Solutional Mine/Milling/Truck (250 metric tons yellowcake per year)	1985
Colstrip	Coal Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1985
	Coal Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1990
	Coal Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1995
	Coal Surface Mine/Synthoil Liquefaction/Pipeline (100,000 bbl/day)	2000
Beulah	Coal (Lignite) Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1980
	Coal (Lignite) Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1982
	Coal (Lignite) Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1987
	Coal (Lignite) Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1995
	Coal (Lignite) Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	2000

MWe = megawatt-electric

MMcfd = million cubic feet per day

bbl/day = barrels per day

MMtpy = million tons per year

[a] See Chapter 3, White, Irvin L., et al. First Year Work Plan for a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1976; and White, Irvin L., et al. Work Plan for Completing a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1978. As explained in Chapter 3, these hypothetical developments are not intended to be identical with announced plans for these same sites.

formulating generalizations about the impacts that can be expected to occur when western energy resources are developed (see the Introduction to Part II).

Table 2-2 indicates the total quantities of energy required from the western U.S. at two national levels of energy consumption in 1980, 1990, and 2000. This table also shows the role of each of these six resources in producing these quantities.[1]

The technological alternatives included in both the site-specific and eight-state area scenarios are described in the following section.

2.4 TECHNOLOGIES FOR DEVELOPING WESTERN ENERGY RESOURCES

In this section, we describe the technologies which are considered in this study. These technologies were selected as being typical of the technologies we believe are likely to be deployed for developing western energy resources during the next 25 years. The technologies deployed are described in the Energy Resource Development Systems (ERDS)[2] Report which are part of the background and supporting materials developed to support the impact and policy analyses. The ERDS description for each of the six resources includes an overview of technological alternatives for exploration, extraction, conversion, and environmental control. These descriptions, written for well-informed laypersons, specify input materials and personnel requirements, outputs and residuals (byproducts), energy requirements, and internalized economic costs. Input, output, residual, and economic costs data from the ERDS are introduced at the appropriate place in each of the impact analysis chapters in this report.

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[1] In our progress report, we used three levels of development or cases based on the Stanford Research Institute's (SRI) interfuel competition model. The model and the three cases are described in Chapter 12 of our progress report (White, Irvin, L., et al. Energy From the West: A Progress Report of a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1977) and in more detail in SRI Decision Analysis Group, Cazalet, Edward, et al. A Western Regional Energy Development Study: Economics, Final Report, 2 vols. Menlo Park, Calif.: Stanford Research Institute, 1976. Only two levels of development are considered in this report. These modify the SRI cases by reducing the level of oil shale development and adding geothermal (which is not included in the SRI model). Table 2-2 reflects these changes.

[2] White, Irvin L., et al. Energy From the West: Energy Resource Development Systems Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

TABLE 2-2: REGIONAL ENERGY DEVELOPMENTS

RESOURCE AND LEVELS OF DEVELOPMENT[a]	TOTAL U.S. PRODUCTION (Q's)			PROJECTED PRODUCTION IN THE EIGHT-STATE STUDY AREA					
				1980		1990		2000	
	1980	1990	2000	Q's	PERCENT U.S. TOTAL	Q's	PERCENT U.S. TOTAL	Q's	PERCENT U.S. TOTAL
Coal									
Nominal Demand	15.12	25.12	50.99	5.03	33.3	12.61	50.2	29.93	58.7
Low Demand	13.36	20.24	38.65	4.28	32.0	9.80	48.4	22.11	57.2
Oil Shale									
Nominal Demand	.001	.95	4.76	.001	100.0	0.95	100.0	4.76	100.0
Low Demand	.001	0.19	1.91	.001	100.0	0.19	100.0	1.91	100.0
Uranium Fuel									
Nominal Demand	5.34	13.90	26.10	4.77	89.3	13.64	91.1	23.75	91.0
Low Demand	4.56	10.40	18.80	4.15	91.0	9.46	91.0	17.11	91.0
Gas (Methane)									
Nominal Demand	23.73	26.02	18.34	1.97	8.3	2.08	8.0	1.06	5.8
Low Demand	23.12	24.61	17.69	1.99	8.6	1.89	7.7	1.19	6.7
Domestic Crude Oil									
Nominal Demand	21.10	25.96	22.79	1.69	8.0	1.32	5.1	1.03	4.5
Low Demand	21.16	25.87	22.62	1.74	8.2	1.34	5.3	.90	4.0
Geothermal[b]									
Nominal Demand			1.49					0.15	10.0
Low Demand			0.21					0.02	10.0

Q = 10^{15} British thermal units. One Q equals approximately 172 million barrels of oil, 60 million tons of western coal, or one trillion cubic feet of natural gas.

[a] See chapter 11 for description of the two levels of development. For the Nominal Demand case in 2000, the total supply is 156.9 Q. For the Low Demand case, the total is 129.5 Q.

[b] The geothermal development is described in White, Irvin L., et al. Work Plan for Completing a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1978. Only development levels for 1985 and 2000 were projected.

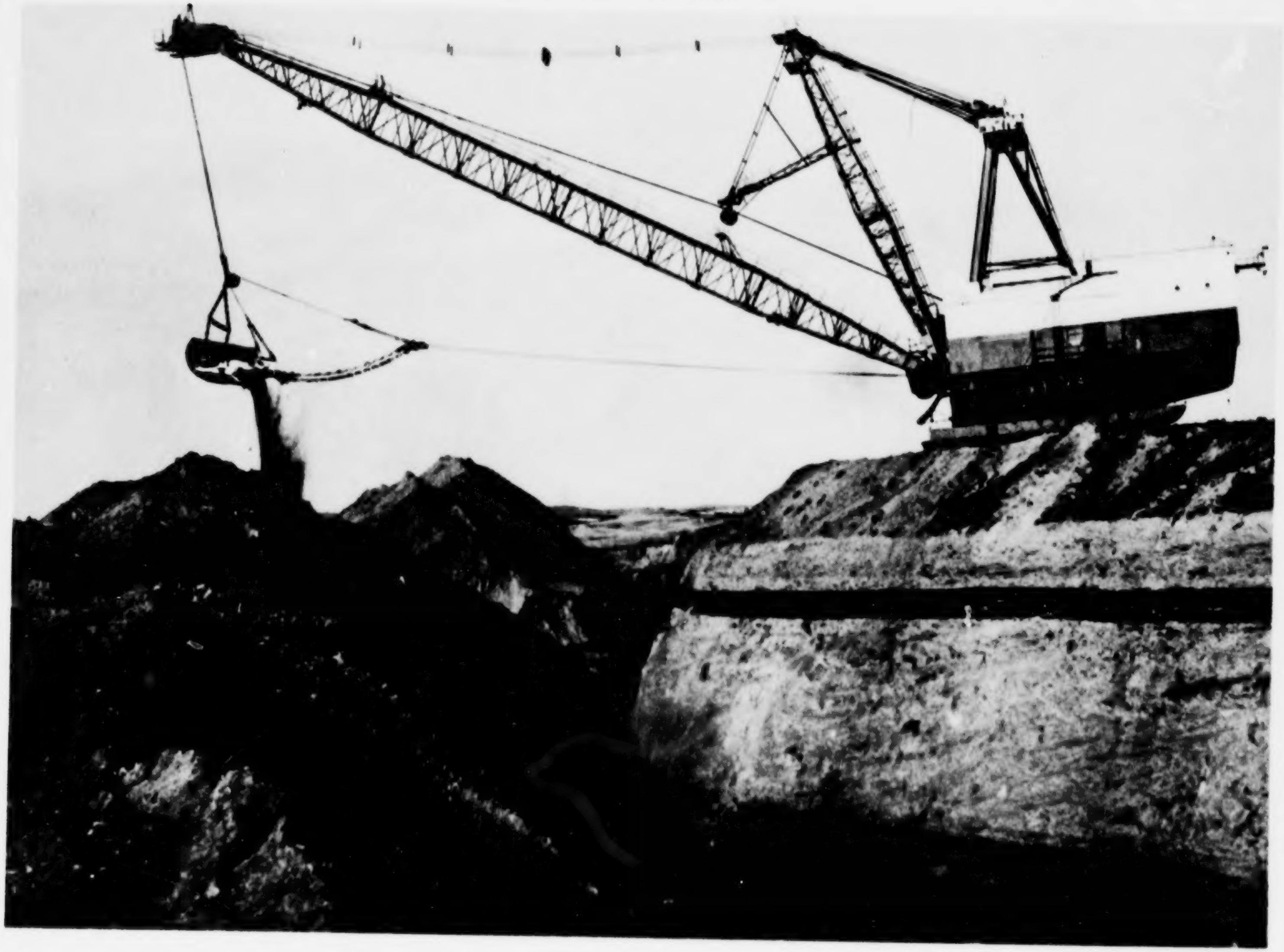

FIGURE 2-2: DRAGLINE USED FOR SURFACE MINING COAL

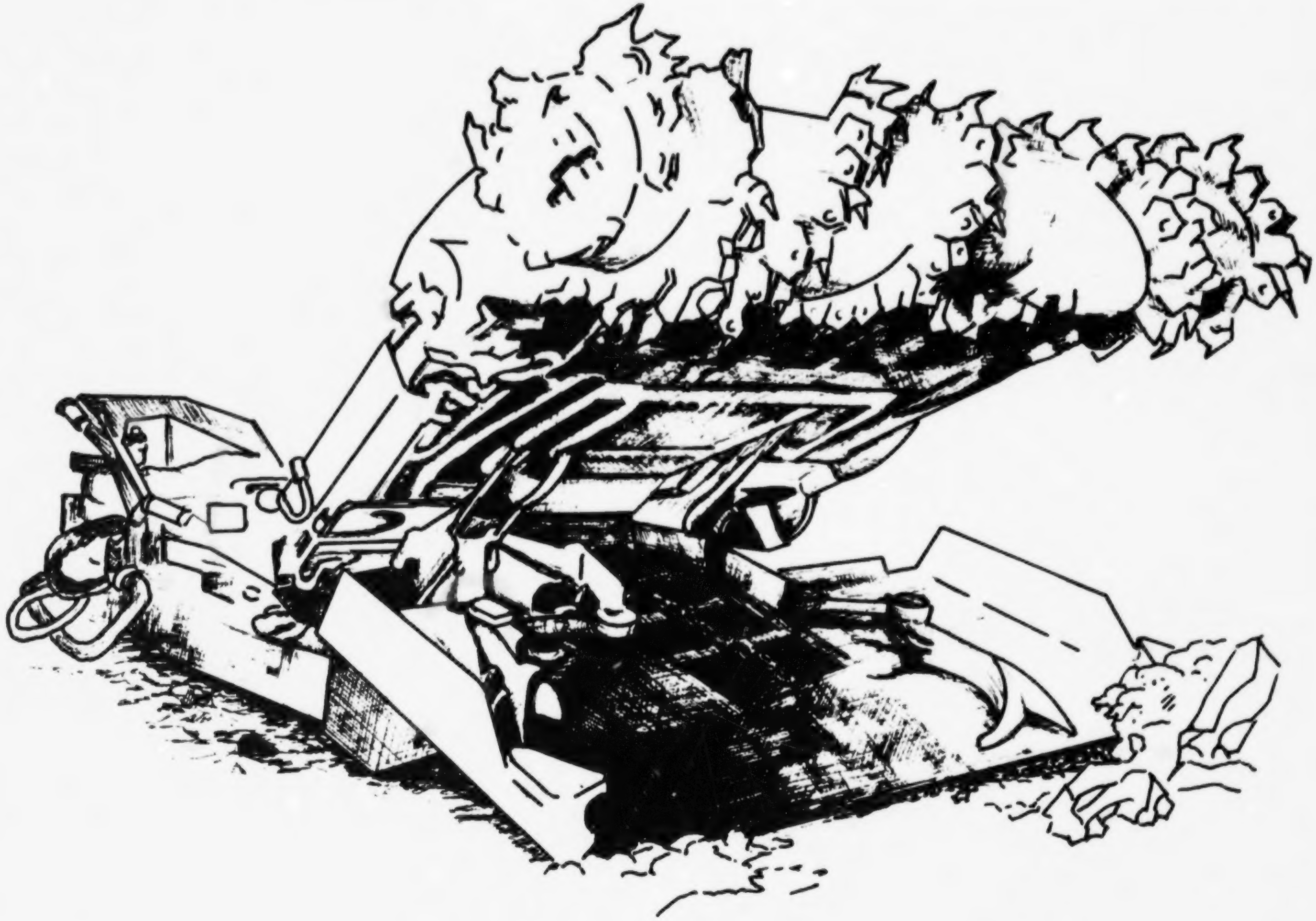

FIGURE 2-3: CONTINUOUS MINER FOR UNDERGROUND MINING OF COAL

The descriptions of the technologies in this section are much less detailed than those presented in the ERDS Report. The technologies will be described by resource in the following sequence: coal, oil shale, uranium, oil, gas, and geothermal. This description will include a brief characterization of the technology and information on the size, efficiency, and load factor which are considered typical and which are assumed in our impact analyses.[1]

2.4.1 Coal Development Technologies

We have analyzed the impacts of coal mining, coal-fired steam-electric power plants, Lurgi and Synthane coal gasification, Synthoil coal liquefaction, and unit train and slurry pipeline coal transportation.

2.4.2 Coal Mining

Two types of coal mining are considered: surface and underground. Area surface mining is assumed at four of the six local sites examined. Surface mining begins with the removal and storage of topsoil from the area to be mined. (Topsoil is stored so that it can be replaced during reclamation.) Overburden, the rock and soil material between the surface and the coal seam, may be loosened by blasting and removed using a dragline. The dragline, usually electrically powered, lifts the overburden and places it on a spoils pile adjacent to the mining area (Figure 2-2). The exposed coal is then mined and loaded into large trucks or onto conveyor belts for transportation to either a conversion or loading facility.

Current regulations require surface-mined lands to be reclaimed. Present practice is for mining and reclamation to proceed simultaneously. Overburden is placed in the mined-out area, graded and contoured; topsoil is then replaced and the area is revegetated. Data on surface mining are shown in Table 2-3.

Underground room and pillar mining is the alternative assumed for the Kaiparowits/Escalante and Rifle sites. As the coal is mined, pillars of coal are left in place to support the roof. (Roof supports are used in addition to the pillars.)

In our scenario, continuous mechanical miners are used (see Figure 2-3). When this mining technology is used, the coal is continuously scraped from the seam and loaded directly onto a conveyor or mine rail car train.

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[1] More detailed technical information is contained in White, Irvin L., et al. Energy From the West: Energy Resource Development Sytems Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming; Coal, Chapter 3; Oil Shale, Chapter 4; Uranium, Chapter 5; Oil, Chapter 6; Natural Gas, Chapter 7; and Geothermal, Chapter 8.

TABLE 2-3: SURFACE COAL MINING DATA

Mine Size	Nominally 12 million tons per year (size varies depending on demand of conversion facility)
Recovery	80-90 percent of resource in place
Reclamation involves separate topsoil retention, replacement of topsoil, returning land to original contours, and revegetation to native cover. Revegetation is thought to require 6 to 9 inches of water per year for five years.	

Reclamation for underground mines involves finding permanent disposal for the spoils mined along with the coal and material removed to gain access to the seam. These materials are usually stabilized with lime and deposited in sealed landfills. Data on underground mining are shown in Table 2-4.

2.4.3 Coal-Fired Steam-Electric Power Plants

The power plants analyzed in this study are assumed to be direct fired boilers producing high pressure, superheated steam which is then expanded in a multistage turbine to produce mechanical energy. The mechanical energy is then converted to electricity in an electrical generator (Figure 2-4). Details of the boiler and turbine design are not considered, but an overall efficiency of 34 percent is assumed for the plant including environmental controls. This level of efficiency for the overall plant could be achieved with a number of alternative systems, but would require a relatively sophisticated boiler-turbine arrangement with superheaters, reheaters, economizers, and preheaters.

Environmental controls for the plant include a wet limestone scrubber for flue gas desulfurization (FGD) and an electrostatic precipitator (ESP) for particulate removal. To examine the sensitivity of impacts to alternative environmental control systems, FGD and ESP efficiencies and stack height are varied in our air impact analyses. No cleanup technology is assumed for oxides of nitrogen.

Because of thermodynamic limitations, almost two-thirds of the heat generated in a power plant boiler must be dissipated. Forced draft, wet cooling towers are assumed in which heat is dissipated by evaporation of water into the atmosphere (Figure 2-5). To examine the sensitivity of impacts to cooling technology, combined wet-dry and dry cooling system costs and water consumption are also examined.

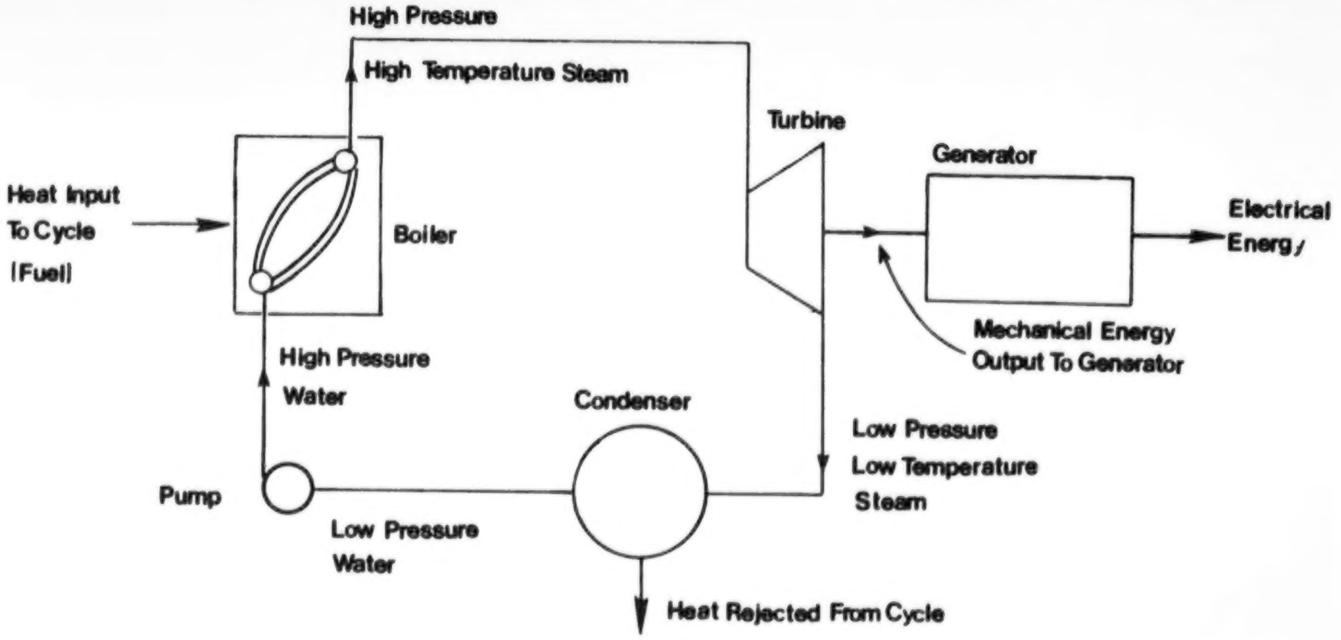
High Pressure
High Temperature Steam
Turbine
Generator
Heat Input
To Cycle
(Fuel)
Boiler
Electrical
Energy
Mechanical Energy
Output To Generator
High Pressure
Water
Condenser
Low Pressure
Low Temperature
Steam
Pump
Low Pressure
Water
Heat Rejected From Cycle

FIGURE 2-4: SIMPLIFIED SCHEMATIC OF A STEAM POWER PLANT

Source: U.S., Atomic Energy Commission. Proposed Final Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington, D.C.: Government Printing Office, 1974, Vol. III, p. 6B.2-3.

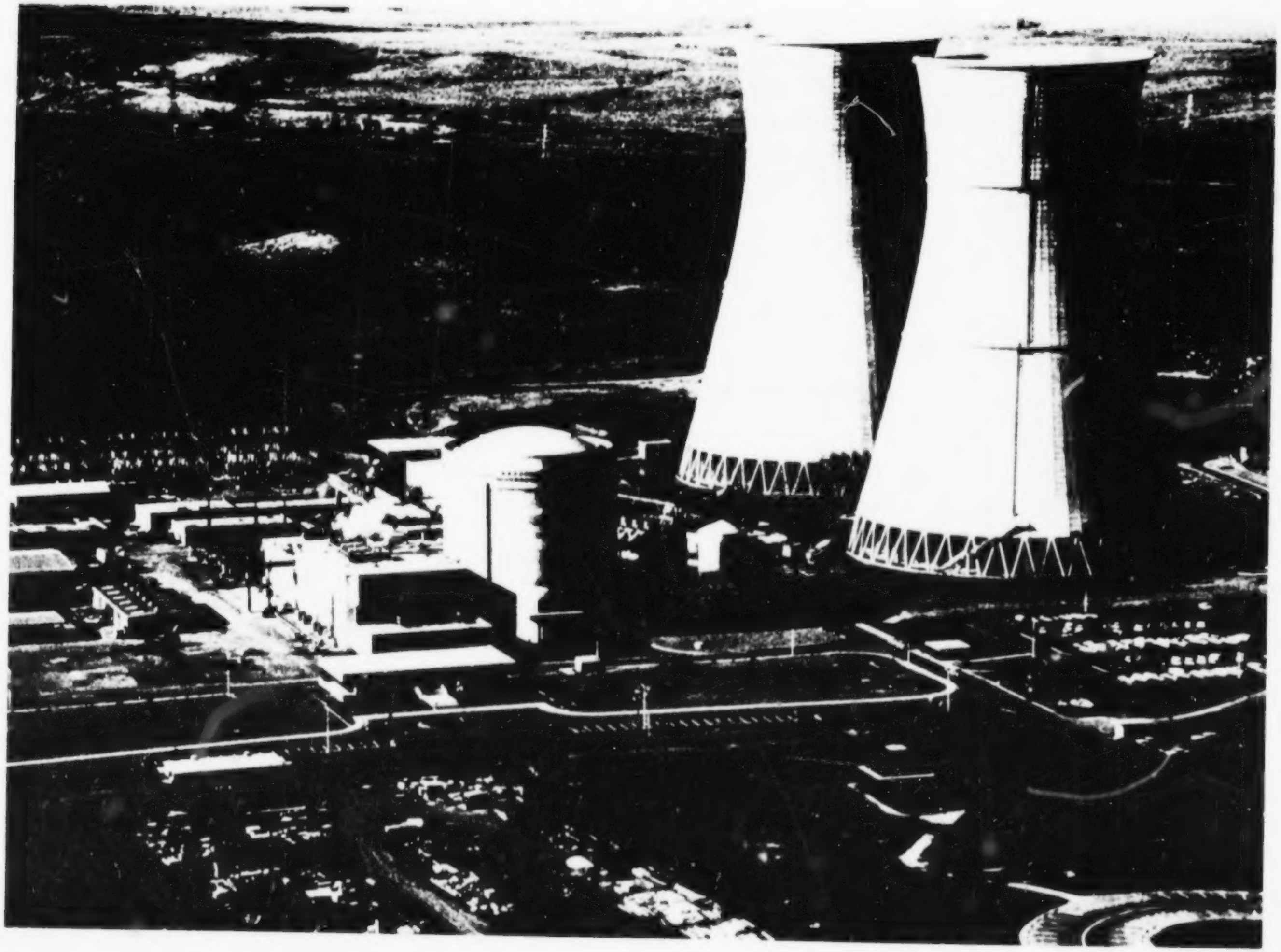

FIGURE 2-5: WET FORCED DRAFT COOLING TOWERS

Source: Sacramento Municipal Utility District; used by permission.

TABLE 2-4: UNDERGROUND COAL MINING DATA

Mine Size	Nominally 3 million tons per year (size and number of mines varies depending on demand of conversion facility)
Recovery	45-50% of resource in place
Reclamation requires waiting 2 years for subsidence and then returning land to original contours and native cover. No reclamation was assumed to be necessary for the underground coal mines in this study.	

Data on coal-fired steam-electric power plants are shown in Table 2-5.

2.4.4 Coal Gasification

Impacts of two coal gasification processes are analyzed. The Lurgi process was selected because it is a presently available commercial scale technology. The Synthane process was selected as representative of a number of second generation processes which are likely to be commercially available by 1985 to 1990.

In coal gasification, coal is transformed into gas by heating (to drive off vapors) and burning it with reduced oxygen and steam

TABLE 2-5: COAL-FIRED POWER PLANT DATA

Plant Size	Nominally 3,000 megawatt-electric output using 4 boilers of 750 megawatts capacity each
Plant Efficiency	34% including environmental controls
Load Factor	75% as an annual average. For worst-case analysis of daily or hourly quantities of pollutants produced, 100% load factor is assumed.
Environmental Controls	99% effective electrostatic precipitator
	80% effective flue gas desulfurization using a wet limestone scrubber
	500 foot stack height
Cooling	Forced draft wet evaporative cooling towers

TABLE 2-6: COAL GASIFICATION PLANT DATA

Plant Size	Nominally 250 million cubic feet per day of 1,000 British thermal units per cubic feet synthetic natural gas
Plant Efficiency	Lurgi process 73% Synthane process 80%
Load Factor	90% as an annual average. For worst-case analysis of daily or hourly quantities of pollutants produced, 100% load factor is assumed.

to produce carbon monoxide and hydrogen (H). This mixture of gases is then upgraded to synthetic natural gas (primarily methane) in a separate reactor using a catalyst.

The Lurgi gasifier uses a moving grate and gasifies with steam and oxygen at pressure of between 300 and 500 pounds per square inch atmosphere (PSIA) and a temperature which varies between 1,800° Fahrenheit (F) at the bottom of the gasifier and 1,000°F at the top (Figure 2-6). Because it uses a grate, the Lurgi fasifier is small, and between 25 and 30 reactors are needed for a 250 million cubic foot per day plant.

The Synthane process is a fluidized bed gasifier involving three separate stages. The first stage pretreats the coal by partly burning it at 1,000 pounds per square inch (psi) and 800°F so that it will not stick together during gasification. The next stage takes place at a slightly higher temperature (about 1,100-1,450°F) and starts the gasification process, while the third stage completes the process at about 1,750-1,850°F. Because it is a pressurized fluidized bed, only one reactor vessel is required for a commercial-size facility, and the Synthane process is expected to operate at 8 to 10 percent higher efficiency than the Lurgi process.

Following both the Lurgi and Synthane basic gasification processes, solids and undesirable byproduct gases are removed before the methane is generated in its reactor. Byproduct gases include carbon dioxide and hydrogen sulfide (H_2S). The H_2S is reduced to elemental sulfur and water in a Claus plant.

Water is used in these facilities both as an input to the gasification process and for cooling. As with the steam-electric power plant, wet, forced draft cooling towers are assumed for cooling. Wet-dry and all dry cooling are also examined.

Data on both gasification facilities are shown in Table 2-6.

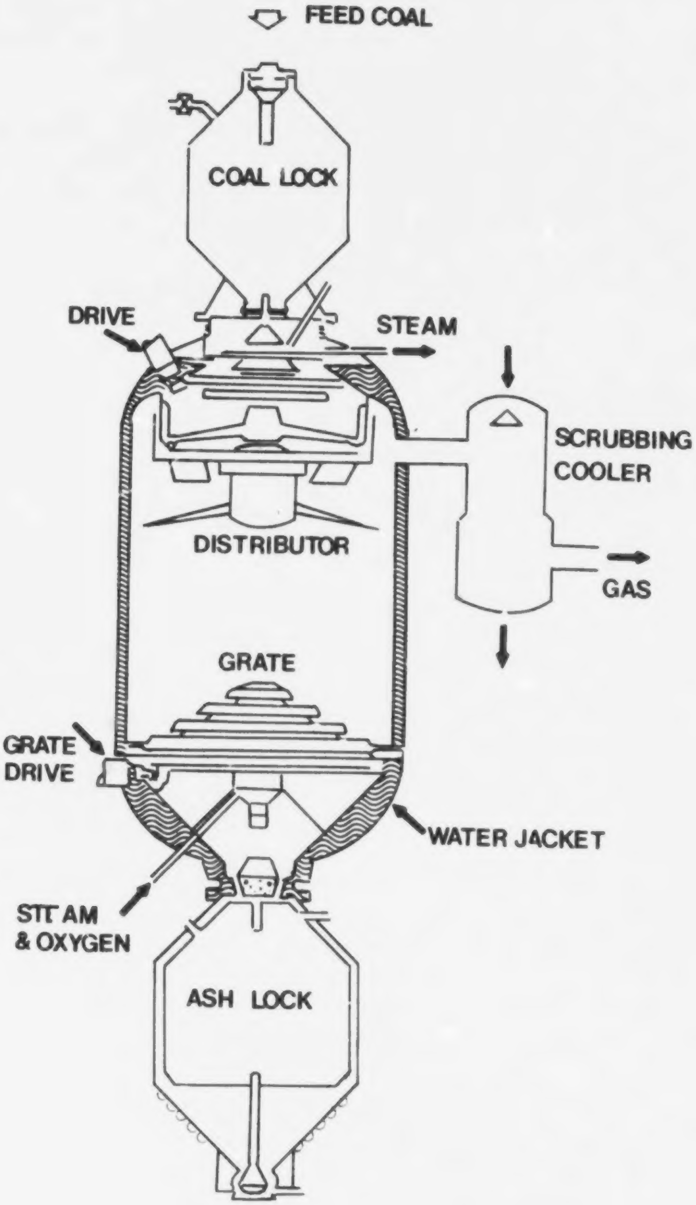
FEED COAL
COAL LOCK
DRIVE
STEAM
SCRUBBING
COOLER
DISTRIBUTOR
GAS
GRATE
GRATE
DRIVE
WATER JACKET
STEAM
& OXYGEN
ASH LOCK

FIGURE 2-6: SCHEMATIC OF A LURGI GASIFIER

TABLE 2-7: COAL LIQUEFACTION PLANT DATA

Plant Size	100,000 barrels per day of synthetic crude with an energy of $5.8X10^6$ Btu/barrel
Plant Efficiency	Synthoil process 92%
Load Factor	90% as an annual average. For worst-case analysis of daily or hourly quantities of pollutants produced, 100% load factor is assumed

Btu = British thermal unit

2.4.5 Coal Liquefaction

Coal liquefaction processes are currently at a much earlier stage of development than gasification, and it is not anticipated that liquefaction will be commercially available before 1995-2000. Data on liquefaction processes is, therefore, somewhat limited and uncertain. The liquefaction process assumed for this study is the Synthoil process developed by the Bureau of Mines.

In the Synthoil process, H is added to the hydrocarbon (HC) molecules in coal through the use of a catalyst so that a liquid is produced. The process requires a pressure of 2,000 to 4,000 psi and high temperature (about 850°F).

In the presence of H, the sulfur in the coal is converted to H_2S gas, and this is removed and converted to elemental sulfur in a Claus plant.

Water is used both for cooling in wet, forced draft cooling towers and as a source of H for the process.

Data on the Synthoil liquefaction facility are shown in Table 2-7.

2.4.6 Coal Transportation[1]

Two transportation options are analyzed for coal, unit trains, and coal slurry pipelines. Unit trains are assumed to be 100 car

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[1] Coal transportation alternatives are not described in the ERDS Report. For a description of unit train and coal slurry pipeline technologies, see Szabo, Michael F. Environmental Assessment of Coal Transportation. Cincinnati, Ohio: U.S., Environmental Protection Agency, Office of Research and Development, Industrial Environmental Research Laboratory, 1977.

TABLE 2-8: UNDERGROUND OIL SHALE MINE DATA

Mine Size	Nominally 24 million tons per year
Recovery	60% of seam mined (lower grade shale above or below that seam is not recovered)

trains with a capacity of 10,000 tons of coal each, powered by six diesel-electric locomotives. Capacity of a unit train system is variable, depending upon the number of trains, their frequency of operation, and whether the right-of-way is single track, double track, or a mixture of the two at various places along the route. Unit trains are assumed to have no water requirements and operate at above 95 percent efficiency.

Coal slurry pipelines utilize water flow to carry pulverized coal. The coal slurry pipeline analyzed is assumed to carry 25 million tons per year of coal. Coal slurry pipelines do not operate economically either at partial capacity or with intermediate delivery points, but they do operate at full capacity more economically than unit trains.

2.4.7 Oil Shale Development Technologies

We have analyzed the impacts of underground oil shale mining and surface retorting using the TOSCO II process, and of modified in situ mining and retorting using the Occidental process.

2.4.8 Underground Oil Shale Mining

Conceptually, underground oil shale mining is similar to underground coal mining, with the room and pillar method being most likely to be used. However, oil shale mines are very large as compared to coal mines, with roof heights of as much as 60 to 80 feet. These large rooms are mined in two zones. The top zone is mined with equipment extracting the shale from the wall or face of the resource, while the bottom zone is mined by extracting the shale from the floor or bench.

The extraction process involves drilling, blasting, and pick up of the loosened ore after which the walls are scraped, or scaled, to remove loose material and the roof is bolted. Large front-end loaders are used to load the mined shale into trucks which transport it to a sizing and crushing facility. The extremely large size of these mines results in the use of some equipment more commonly seen in surface mines, such as large trucks and drill rigs. A schematic of an underground oil shale mine is shown in Figure 2-7, and data on underground mines is given in Table 2-8.

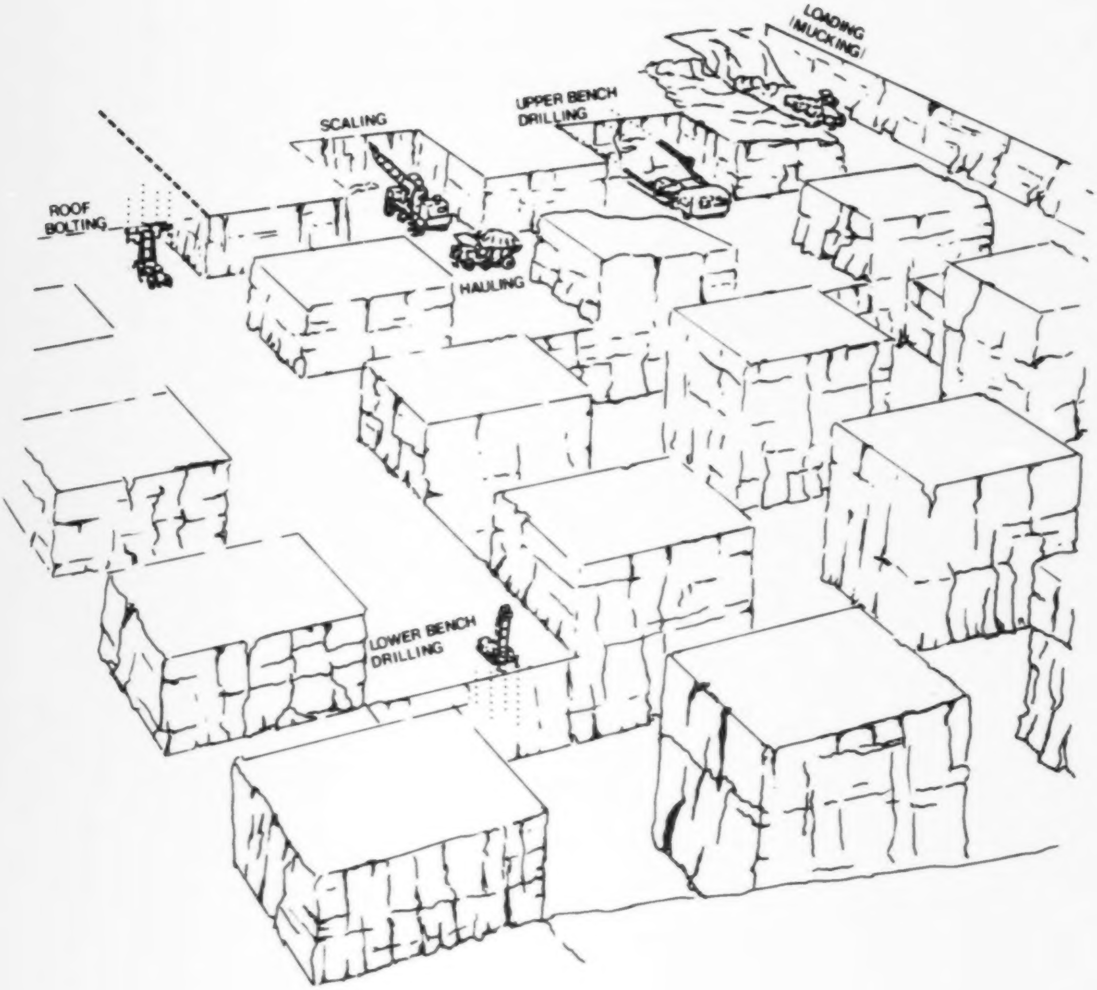
LOADING (MUCKING)
UPPER BENCH DRILLING
SCALING
ROOF BOLTING
HAULING
LOWER BENCH DRILLING

FIGURE 2-7: OIL SHALE ROOM-AND-PILLAR MINING

Source: Ashland Oil, Inc. and Shell Oil Co. Detailed Development Plan and Related Materials for Oil Shale Tract C-b. Volume Prepared for Area Oil Shale Supervisor February 1976. p. 11-23.

(Originally reported in: Colony Development Operation. An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado. Volume I, 1974. p. 11)

TABLE 2-9: SURFACE OIL SHALE RETORTING DATA

Plant Size	Nominally 50,000 barrels per day of synthetic crude with an energy of $5.8X10^6$ British thermal units per barrel
Plant Efficiency	100% of Fischer assay of oil in shale recovered
Load Factor	90% as an annual average. For worst-case analysis of daily or hourly quantities of pollutants, 100% load factor is assumed

2.4.9 Surface Oil Shale Retorting

TOSCO II surface retorting is assumed to use the shale from the underground mine. In the TOSCO II retort, one-half inch diameter ceramic balls are heated to about 900°F and then put into the retort with small pieces of raw shale. The retort vessel is rotated so that the balls heat the shale by contact and, at the same time, crush it to a powder. This heating process is done in an inert gas atmosphere rather than air, so that the shale oil released does not burn. The oil is collected, and the pulverized spent shale is separated from the balls with moving screens and carried away for disposal. The gas generated, which is a low energy HC gas, is collected and used as a fuel in the heater for the ceramic balls.

Because the energy content of shale is relatively low (only about 25 to 35 gallons of shale oil can be obtained from a ton of ore), a large quantity of spent shale must be disposed of. The pulverized spent shale from the TOSCO II process can be set as a cement with about 13 percent water; this cement is stable enough for permanent disposal. Plans for shale disposal assume that a small canyon in the vicinity of the retort will be used for disposal and filled with the shale cement to depths of a few hundred feet. The disposal area will then be covered with topsoil and vegetated.

Data on surface retorting using the TOSCO II process are given in Table 2-9.

2.4.10 _In Situ_ Oil Shale Retorting

The Occidental modified _in situ_ retorting process is assumed as an alternative to surface retorting. In the modified _in situ_ process, oil shale is mined from a region below a high quality ore,

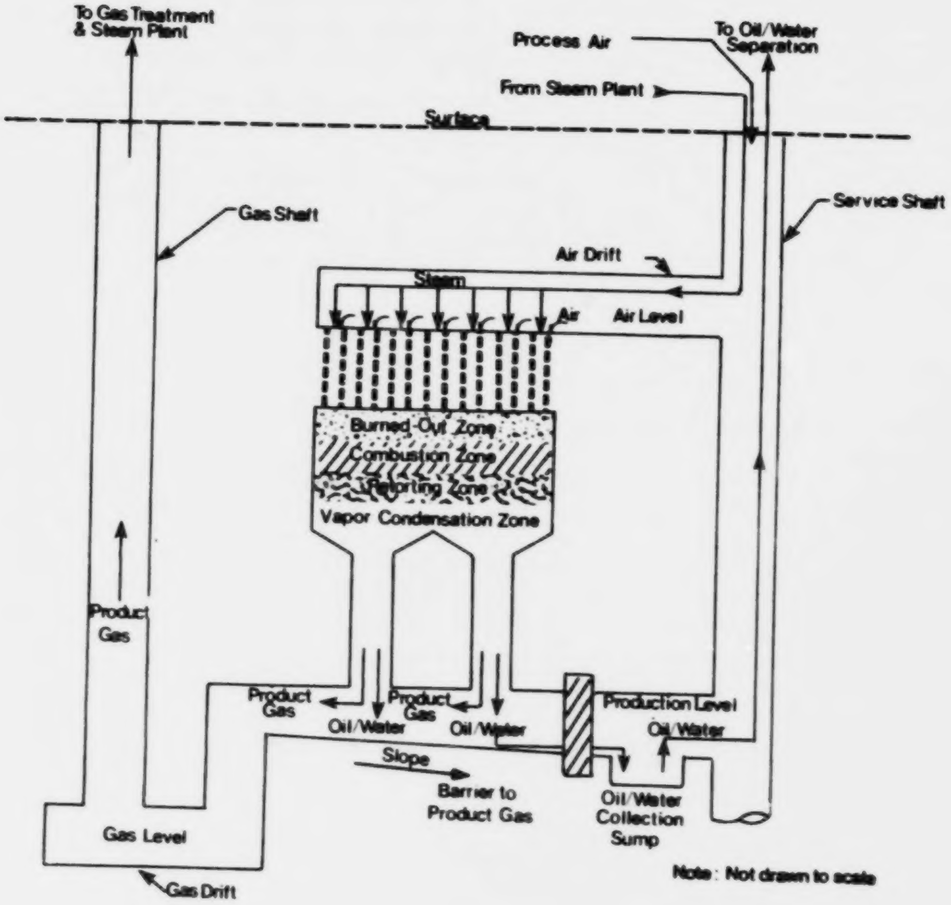
To Gas Treatment & Steam Plant
Process Air
To Oil/Water Separation
From Steam Plant
Surface
Gas Shaft
Service Shaft
Air Drift
Steam
Air
Air Level
Burned-Out Zone
Combustion Zone
Retorting Zone
Vapor Condensation Zone
Product Gas
Product Gas
Product Gas
Oil/Water
Oil/Water
Production Level
Oil/Water
Slope
Barrier to Product Gas
Oil/Water Collection Sump
Gas Level
Gas Drift
Note: Not drawn to scale

FIGURE 2-8: SIMPLIFIED DRAWING OF AN OPERATING MODIFIED *IN SITU* OIL SHALE RETORT

Source: Ashland Oil, Inc., and Occidental Oil Shale, Inc. *Supplemental Material to Modified Detailed Development Plan for Oil Shale Tract C-b*, prepared for Area Oil Shale Supervisor. June 1977.

TABLE 2-10: MODIFIED IN SITU OIL SHALE FACILITY DATA

Plant Size	Nominally 57,000 barrels per day of synthetic crude with an energy of 5.8 X 10^6 British thermal units per barrel
Plant Efficiency	40% recovery of oil in place in mined seams
Load Factor	90% as an annual average. For worst-case analysis of daily or hourly quantities of pollutants produced, 100% load factor is assumed

and this ore is discarded as a spoil. The high grade ore is then broken into rubble with shaped charge blasting to form large *in situ* retorts of over 100 feet on a side and nearly 300 feet high. Air and steam are circulated through the shale rubble and the shale is heated until it ignites in a burning front which burns from the top down the retort, releasing shale oil ahead of the combustion. The shale oil is collected in sumps, and the gases produced are treated to recover additional energy and reduce emissions. A much smaller quantity of shale must be handled with *in situ* retorting than for surface retorting, and the disposed of raw shale is more stable than processed shale from surface retorting. A sketch of the modified *in situ* retorting is shown in Figure 2-8, and data on the process are shown in Table 2-10.

2.4.11 Uranium Development Technologies

We have analyzed the impacts of surface, underground, and solutional uranium mining, and of acid leach milling of the ore from surface and underground mines to produce yellowcake (uranium oxide [U_3O_8]).

2.4.12 Surface Uranium Mining

A surface uranium mine (assumed in the Gillette scenario) is more similar to pit mining than to the area mining typically used to recover coal. The uranium is located in veins which vary in terms of the quality of ore and are irregular in location. Mining is therefore carried out selectively, with lower quality ore left as a spoil. In addition, as truckloads of ore leave the pit, radioactivity is measured to grade the ore for milling. The equipment used for mining is similar to that used for coal but usually smaller in size because of the smaller quantities or ore involved.

Reclamation of uranium mines includes layering the overburden by composition to limit the potential for damage from trace

TABLE 2-11: SURFACE URANIUM MINING DATA

Mine Size	Nominally 440,000 tons per year of ore generally expressed as 1100 metric tons per day
Recovery	95% of resource in place

TABLE 2-12: UNDERGROUND URANIUM MINING DATA

Mine Size	Nominally 440,000 tons per year of ore generally expressed as 1100 metric tons per day
Recovery	50% of resource in place

elements in the overburden leaching into groundwater and to assure stabilization of materials which may be radioactive.

Data on uranium surface mining are shown in Table 2-11.

2.4.13 Underground Uranium Mining

Underground uranium mining in the Navajo/Farmington scenario is assumed to use a room and pillar method because of the anticipated nature of the uranium resource in this area. Additional roof support using timbers is also assumed. Ore is mined using continuous miners and removed by conveyors to the access shaft where self-dumping buckets are used to haul the ore out of the mine.

Reclamation is only assumed to be necessary for solid waste from the mine. Thus reclamation will be limited to stabilizing the solid wastes, placing topsoil over the landfill, and revegetating the area. The land area used for this landfill is small.

Data on underground uranium mining are shown in Table 2-12.

2.4.14 Solutional Uranium Mining

Solutional uranium mining was selected for one of the uranium mines in the Gillette scenario in order to present a comparison with surface mining, and also because the irregular seams or veins and nature of the geology of the resource made this the most economical mining technique. For solutional mining, an alkaline solution is injected into the ore formation through a group of injection wells. This solution dissolves the uranium compounds, and

TABLE 2-13: SOLUTIONAL URANIUM MINING DATA

Plant Size	250 tons per year of yellowcake
Plant Efficiency	60 to 70% of resource in place
Load Factor	100%

TABLE 2-14: URANIUM MILLING PLANT DATA

Plant Size	1,000 metric tons of yellowcake per year
Plant Efficiency	93%
Load Factor	100%

this "pregnant" solution of uranium is pumped out of the formation in recovery wells. The solution is then processed to recover yellowcake, so that the mining and milling processes are combined in solutional mining.

Reclamation after solutional mining involves cleansing the groundwater in the mined-out area to insure that uranium and other heavy metal compounds do not remain. This is accomplished by pumping clean water into the formation and recovering the remaining alkaline solution and dissolved compounds. The recovered solution is either cleaned or disposed of in an evaporative pond.

Data on solutional uranium mining are shown in Table 2-13.

2.4.15 Uranium Milling

Uranium milling is a process by which U_3O_8 is extracted from uranium ore and concentrated into a "yellowcake" which is about 90 percent U_3O_8. The milling process assumed in this analysis is acid leaching. The ore is crushed, slurried (mixed with water and carried along as the water flows), and pumped into heated, agitated tanks where sulfuric acid is added. The uranium ore dissolves in the acid, and the solution is then separated from the waste materials, or tailings, which are discarded in a tailings pond. The solution is concentrated with additional chemical processes, and finally, the U_3O_8 is separated out of the solution and dried for shipment.

Shipment of the yellowcake is assumed to be by truck. Data on uranium milling are given in Table 2-14.

TABLE 2-15: CONVENTIONAL OIL PRODUCTION DATA

Field Size	Nominally 100,000 barrels per day of crude with an energy content of 5.8 X 10^6 British thermal units per barrel; 400 wells required
Recovery	50% of original oil in place

TABLE 2-16: STEAM FLOODING ENHANCED OIL RECOVERY DATA

Field Size	Nominally 100,000 barrels per day of crude with an energy content of 5.8 X 10^6 British thermal units per barrel; 400 wells required
Recovery	10% of original oil in place

2.4.16 Oil Development Technologies

We have analyzed the impacts of conventional oil production and enhanced production using steam flooding.

2.4.17 Conventional Oil Production

Oil production is assumed to include rotary drilled wells in which water based mud is used as a drilling fluid and to remove cuttings. The wells are assumed to be lined with steel pipe casing cemented in place, and the oil is produced through tubing going from the bottom of the well in the oil reservoir to the surface. No wellhead processing of the oil is assumed except for water removal after which the oil is piped out of the region to be refined.

Data on conventional oil production are shown in Table 2-15.

2.4.18 Enhanced Oil Recovery

The enhanced oil recovery method analyzed is steam flooding. Two sets of wells are used, one to inject the steam and the second to recover the oil and water mixture. The steam increases the temperature of the oil so that its viscosity is reduced and it flows more readily. The oil is then pushed by the steam pressure to the recovery wells. Most of the steam injected is recovered as water in a mixture with the oil, and this water must be disposed of in evaporation ponds or cleaned and recycled to the steam generators.

Data on steam flooding are shown in Table 2-16.

TABLE 2-17: NATURAL GAS PRODUCTION DATA

Field Size	Nominally 250 million cubic feet per day of 1,000 British thermal units per cubic foot gas
Recovery	90% of gas in place

2.4.19 Natural Gas Development Technologies

Conventional drilling and production of natural gas are analyzed. As with oil, rotary drilling was assumed using water based mud as a drilling fluid. Wells are assumed to be cased with a heavy pipe cemented in place, and the gas is produced through smaller diameter tubing from the production zones. Surface drying is assumed for the gas using a glycol drying process in which a combination of heat and the glycol vapor are used to dry the gas.

Data on natural gas production are shown in Table 2-17.

2.4.20 Geothermal Development Technologies

Electric power generation from both high temperature hot water and hot dry rock geothermal resources are analyzed.

2.4.21 Hot Water Geothermal

Hot water geothermal development is analyzed because that is one of the most likely geothermal resources to be developed in the eight-state study area. The resources are assumed to have a temperature above 150°C. Power production is assumed to use either a flashed steam or binary cycle process.

In the flashed steam process, the hot, high pressure water is expanded to a low pressure so that it vaporizes. The vapor is then used to drive a low pressure turbine which in turn drives an electric generator. If the hot water is of low quality, and has salts or solid particulates entrained, the flashed steam must be cleaned before entering the turbine.

In the binary cycle process, the hot water is used to heat another fluid with a lower boiling point such as propane, which is then vaporized and used to power a turbine. The binary cycle has fewer problems with low quality water but is more complicated than the flashed steam process. In both processes, cooling calls for wet cooling towers which use the geothermal condensate as a source of water.

TABLE 2-18: HOT WATER GEOTHERMAL POWER PRODUCTION DATA

Facility Size	100 megawatts of electric power output; 60 wells for steam flashing cycle; 55 wells for binary fluid cycle
Efficiency	9-10% for steam flashing cycle; 10-11% for binary cycle
Load Factor	70%

TABLE 2-19: HOT ROCK GEOTHERMAL POWER PRODUCTION DATA

Facility Size	100 megawatts of electric power output; 6 wells
Efficiency	16-18%
Load Factor	70%

Data on flashed steam and binary cycle geothermal power generation are shown in Table 2-18.

2.4.22 Hot Dry Rock Geothermal

The hot dry rock geothermal system uses two sets of wells, one set for injection and one set for recovery of water. After injection, the water is heated by the hot rock to a temperature of 250°C. This hot water is used to heat a second working fluid in a heat exchanger. The remainder of the power production process proceeds the same as for the binary cycle process described above for hot water resources. For hot dry rock development, however, water must be supplied both for injection to recover the heat, and for cooling.

Data on hot dry rock geothermal power generation are given in Table 2-19.

2.4.23 Summary

With the exception of enhanced oil recovery and geothermal, the technologies described above are hypothesized to be placed at specific sites in the eight western states. In the following chapters, the impacts of those hypothetical developments are analyzed and described. In addition, impacts on the region from overall levels of development are analyzed, and that analysis includes enhanced oil recovery and geothermal facilities.

CHAPTER 3

THE IMPACTS OF WESTERN ENERGY RESOURCE DEVELOPMENT: SUMMARY AND CONCLUSIONS

3.1 INTRODUCTION

This chapter summarizes the findings from our assessment of the potential impacts from the development of coal, geothermal, natural gas, oil, oil shale, and uranium resources in eight western states. Although development alternatives for all six of these energy resources have been considered, coal resource development has been emphasized.[1] As shown in Figure 3-1, coal development alternatives include surface and underground mining, on-site electrical power generation, conversion to synthetic fuels (gasification and liquefaction), and the export of raw coal by unit train and slurry pipeline. Electricity will be transported by extra-high voltage (EHV) transmission lines, and gases and liquids by pipelines.

Underground mining and surface retorting, modified *in situ* processing, and transport by pipeline make up the oil shale resource development alternatives considered. Oil and natural gas development includes conventional drilling and transportation by pipeline as well as enhanced recovery technologies. Uranium development includes surface mining, underground mining, solutional mining, milling, and then transportation. Geothermal development includes drilling, production of hot water, and conversion to electricity.

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[1] Development alternatives are summarized in the Introduction to Part II and in Chapters 4-11. Detailed descriptions of the technological alternatives for developing each of the six energy resources were prepared as background and supporting materials for the impact and policy analyses. These descriptions provide baseline data on the technologies (demands, products, and residuals), characterize the resources, and describe the principal laws and regulations that apply to the deployment and operation of the technologies. See White, Irvin L., *et al*. *Energy From the West: Energy Resource Development Systems Report*. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

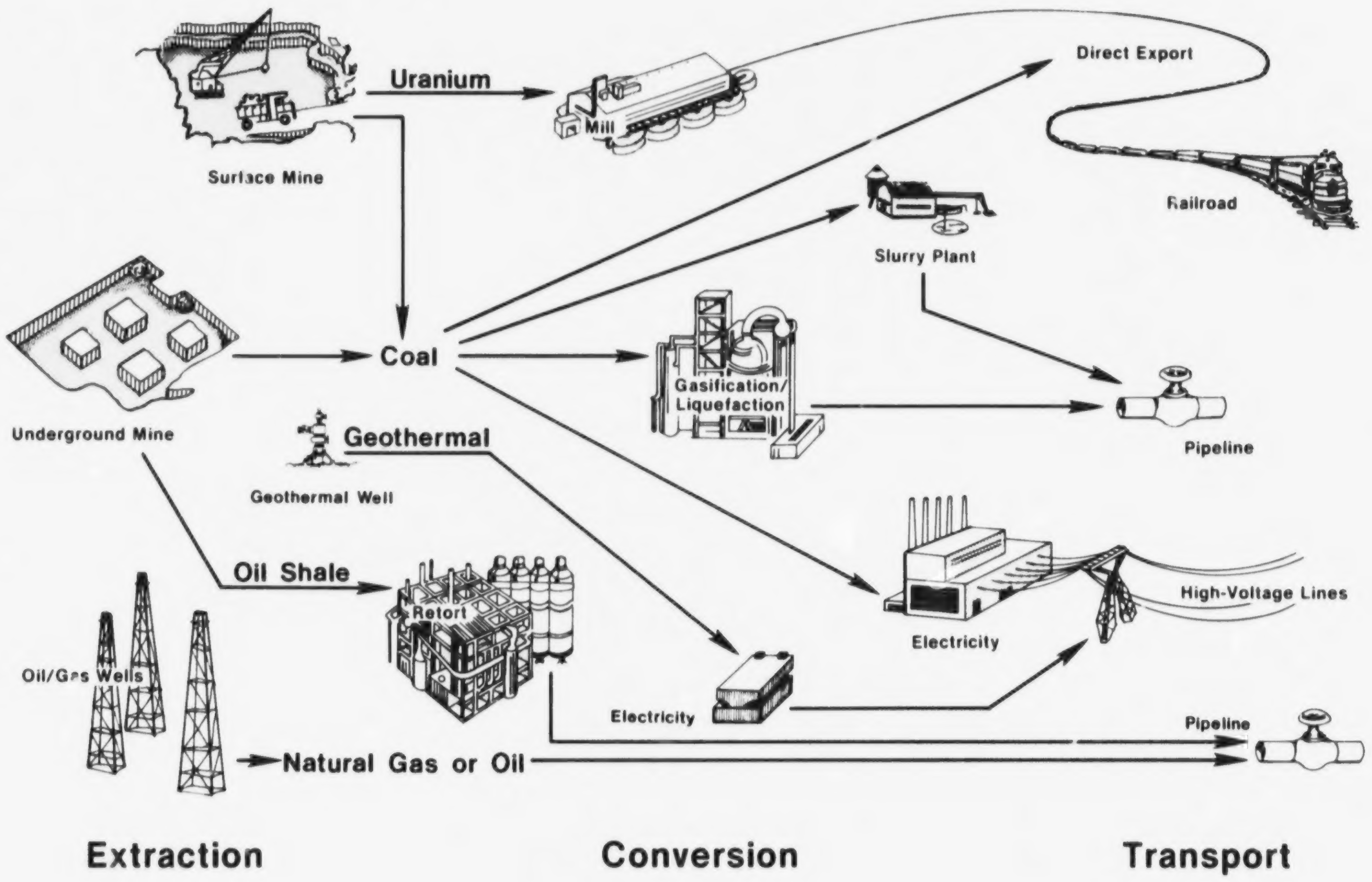
Surface Mine
Uranium
Mill
Direct Export
Railroad
Underground Mine
Coal
Slurry Plant
Gasification/
Liquefaction
Pipeline
Geothermal
Geothermal Well
Oil Shale
Retort
Electricity
High-Voltage Lines
Oil/Gas Wells
Electricity
Pipeline
Natural Gas or Oil
Extraction
Conversion
Transport

FIGURE 3-1: ENERGY RESOURCE DEVELOPMENT

The organizing concept used to structure the impact analyses is based on the fact that impacts occur when a technology interacts with the conditions that exist at the location where the technology is deployed. What these impacts are depends on: the resource demands the technology creates; the unwanted by-products or residuals it produces (e.g., air pollution); the physical and social environmental conditions that exist at the site (such as present population, lifestyle, topography, and climate); and the scale, rate, pattern, and timing of the development.

Seven energy resource development scenarios were used to organize various combinations of the development alternatives depicted in Figure 3-1 and to structure the impact analyses. Six of these scenarios are site-specific; they call for the deployment of typical energy development technologies at six representative sites in the eight-state study area. The seventh scenario is used to structure the analysis on a regional basis, it calls for two levels of energy development within the eight-state area from the present to the year 2000.

Table 3-1 identifies the six sites selected, lists hypothetical energy developments at each, and indicates when each of the facilities are to be operational. As Table 3-1 indicates, several process mixes, development schedules, and scales of development have been included in the scenarios. The number and mix of technologies was chosen to provide for the analysis of a variety of technology and location combinations.

Table 3-2 indicates the total quantities of energy required from the Western U.S. at two national levels of energy consumption in 1980, 1990, and 2000. This table also shows the role of each of the six resources in producing these total quantities.[1] To complete the picture of the regional development being assessed, Table 3-3 identifies the number and kinds of facilities that would be required in the Low Demand case for each resource in each of two major subregions utilized in the study: Rocky Mountain (which includes New Mexico, Utah, and Colorado) and Northern Great Plains (which includes Wyoming, Montana, and North Dakota).

Together, these seven scenarios provide an organizing analytical structure for estimating impacts likely to occur when typical energy development technologies are deployed under representative existing conditions. Results of the six site-specific impact

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[1] The two levels of development were established using the Stanford Research Institute's (SRI) interfuel competition model. The model and the two cases are described in Chapter 11 and in more detail in Cazalet, Edward, et al. A Western Regional Energy Development Study: Economics, Final Report, 2 vols. Menlo Park, Calif.: Stanford Research Institute, 1976.

TABLE 3-1: SITE-SPECIFIC ENERGY DEVELOPMENTS[a]

SITE	HYPOTHETICAL ENERGY DEVELOPMENT	ON-LINE
Kaiparowits/ Escalante	Coal Underground/Electrical Generation/Transmission (3,000 MWe)	1983
	Coal Underground/Electrical Generation/Transmission (3,000 MWe)	1987
Navajo/ Farmington	Coal Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1985
	Coal Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1980
	Coal Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1990
	Coal Surface Mine/Synthoil Liquefaction/Pipeline (100,000 bbl/day)	2000
	Uranium Underground Mine/Milling/Truck (1,000 metric tons yellowcake per year)	1985
Rifle	Oil Shale Underground Mine/TOSCO II Retorting/Upgrading/Pipeline (50,000 bbl/day)	1985
	Oil Shale Modified *In Situ* Retorting/Upgrading/Pipeline (57,000 bbl/day)	1990
	Coal Underground Mine/Electrical Generation/Transmission (1,000 MWe)	1980
	Oil Wells/Pipeline (400 wells, 50,000 bbl/day)	1985
Gillette	Coal Surface Mine/Rail Transport (25 MMtpy)	1980
	Coal Surface Mine/Slurry Pipeline (25 MMtpy)	1985
	Coal Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1985
	Coal Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1985
	Coal Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1995
	Coal Surface Mine/Synthoil Liquefaction/Pipeline (100,000 bbl/day)	2000
	Gas Wells/Beneficiation/Pipeline (83 wells, 250 MMcfd)	1979

TABLE 3-1: (continued)

SITE	HYPOTHETICAL ENERGY DEVELOPMENT	ON-LINE
Gillette (Continued)	Uranium Surface Mine/Milling/Truck (1,000 metric tons yellowcake per year)	1985
	Uranium Solutional Mine/Milling/Truck (250 metric tons yellowcake per year)	1985
Colstrip	Coal Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1985
	Coal Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1990
	Coal Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1995
	Coal Surface Mine/Synthoil Liquefaction/Pipeline (100,000 bbl/day)	2000
Beulah	Coal (Lignite) Surface Mine/Electrical Generation/Transmission (3,000 MWe)	1980
	Coal (Lignite) Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1982
	Coal (Lignite) Surface Mine/Lurgi High-Btu Gasification/Pipeline (250 MMcfd)	1987
	Coal (Lignite) Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	1995
	Coal (Lignite) Surface Mine/Synthane High-Btu Gasification/Pipeline (250 MMcfd)	2000

MWe = megawatt-electric
MMcfd = million cubic feet per day
bbl/day = barrels per day
MMtpy = million tons per year

[a] See Chapter 3, White, Irvin L., et al. First Year Work Plan for a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1976; and White, Irvin L., et al. Work Plan for Completing a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1978. As explained in Chapter 3, these hypothetical developments are not intended to be identical with announced plans for these same sites.

TABLE 3-2: REGIONAL ENERGY DEVELOPMENTS

RESOURCES AND LEVELS OF DEVELOPMENT	TOTAL U.S. PRODUCTION (Q's)			PROJECTED PRODUCTION IN THE EIGHT-STATE STUDY AREA					
				1980		1990		2000	
	1980	1990	2000	Q's	PERCENT U.S. TOTAL	Q's	PERCENT U.S. TOTAL	Q's	PERCENT U.S. TOTAL
Coal									
Nominal Demand	15.12	25.12	50.99	5.03	33.3	12.61	50.2	29.93	58.7
Low Demand	13.36	20.24	38.65	4.28	32.0	9.80	48.4	22.11	57.2
Oil Shale									
Nominal Demand	.001	0.95	4.76	.001	100.0	.95	100.0	4.76	100.0
Low Demand	.001	.19	.95	.001	100.0	.19	100.0	.95	100.0
Uranium Fuel									
Nominal Demand	5.34	13.90	26.10	4.77	89.3	13.64	91.1	23.75	91.0
Low Demand	4.56	10.40	18.80	4.15	91.0	9.46	91.0	17.11	91.0
Gas (Methane)									
Nominal Demand	23.73	26.02	18.34	1.97	8.3	2.08	8.0	1.06	5.8
Low Demand	23.12	24.61	17.69	1.99	8.6	1.89	7.7	1.19	6.7
Domestic Crude Oil									
Nominal Demand	21.10	25.96	22.79	1.69	8.0	1.32	5.1	1.03	4.5
Low Demand	21.16	25.37	22.62	1.74	8.2	1.34	5.3	.90	4.0
Geothermal									
Nominal Demand	0	.15	1.49	0	0	0.012	8.0	0.15	10.0
Low Demand	0	.07	0.21	0	0	0.005	8.0	0.02	10.0
Total Q's									
Nominal Demand	65.29	92.10	124.47	13.46	20.6	30.61	33.2	60.68	48.8
Low Demand	62.20	80.88	98.92	12.16	19.5	22.68	28.0	42.28	42.7

Q = 10^{15} British thermal units. One Q equals approximately 172 million barrels of oil, 60 million tons of western coal, or one trillion cubic feet of natural gas.

TABLE 3-3: NUMBER OF FACILITIES REQUIRED FOR LOW DEMAND CASE

FACILITY TYPE	FACILITY SIZE	NUMBER OF FACILITIES REQUIRED					
		ROCKY MOUNTAIN			NORTHERN GREAT PLAINS		
		1980	1990	2000	1980	1990	2000
Coal Mines	5 MMtpy	13	17	23	38	99	237
Coal Gasification	250 MMscfd	0	0	1	0	2	27
Coal Liquefaction	100,000 bbl/day	0	0	0	0	0	2
Coal Electric Power	3000 MWe	2	3	3	4	10	14
Oil Shale: TOSCO II	100,000 bbl/day	0	0	2	0	0	0
Oil Shale: *In situ*	100,000 bbl/day	0	1	3	0	0	0
Uranium (yellowcake)	1,000 tpy	9	20	35	5	12	22
Natural Gas	250 MMscfd	22	21	13	0	0	0
Crude Oil	100,000 bbl/day	8	6	5	0	0	0
Geothermal	100 MWe	0	1	10	0	0	0

MMtpy = million tons per year
MMscfd = million standard cubic feet per day
bbl = barrels

MWe = megawatt-electric
tpy = tons per year

analyses are reported in Chapters 4-10. These results are the basis for the conclusions concerning local impacts and generalizations about technologies and existing conditions included in this chapter. Likewise, the levels of development, facilities, and time frame outlined in Tables 3-2 and 3-3 provide the structure for the analysis of regional impacts described in Chapter 11; the results of those analyses are the basis for the summary discussion of regional impacts and the factors which cause them. In the summary of regional impacts that follows, the focus is on the Low Demand case since this is felt to represent a more realistic level of development for the region through the year 2000.

This chapter identifies the technological and locational factors that produce significant impacts in seven categories: air; water; social and economic; ecological; health effects; transportation; and aesthetics and noise. Impacts within each category are identified as being primarily a consequence of the technology, conditions existing at the deployment location, and the interaction of technological and locational factors. It should be emphasized that the following discussions are summaries of the impacts which are described in Chapters 4-11. For more detailed explanations (including more extensive references) the reader is referred to the appropriate following chapters.

3.2 AIR QUALITY

HIGHLIGHTS

- **CRITICAL FACTORS**
  - *Two technological factors can significantly affect air quality impacts: emissions quantities and labor intensiveness.*
  - *Three locational factors can also significantly affect these impacts: coal characteristics, dispersion potential, and terrain features.*
- **EMISSIONS**
  - *More sulfur dioxide (SO_2), particulates, oxides of nitrogen (NO_x), and carbon dioxide (CO_2) are emitted by electric power plants than by any other conversion technology included in this study.*
  - *Less of these four criteria pollutants are emitted by Lurgi gasification facilities than by any other conversion technology.*

- On the basis of an equivalent amount of energy produced, above ground oil shale retorting and natural gas processing emit the greatest quantities of hydrocarbons (HC); although there is great uncertainty regarding oil shale emission figures, emissions of HC by modified in situ oil shale facilities are estimated to be ten times less than from an above ground facility.

AMBIENT AIR IMPACTS

- Peak ground-level concentrations of particulates, nitrogen dioxide (NO_2), and HC produced by energy related urban development are usually higher than those produced by the energy facilities themselves.
- The state ambient air quality standard in Colorado is the most restrictive standard limiting SO_2 emissions from power plants in that state.
- Fugitive HC emissions resulting from oil shale retorting, coal liquefaction, and natural gas production of the size modeled are expected to cause the federal 3-hour ambient air quality standard to be exceeded.
- Facilities for producing synthetic fuels from coal can usually meet all federal and state standards except for HC in the case of coal liquefaction and TOSCO II shale oil production.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

- Federal Class II PSD standards are the most restrictive of all the standards for SO_2 emissions from power plants in three of the states studied (North Dakota, New Mexico, and Utah).
- Even when equipped with 80-percent efficient scrubbers, electric power plants of the size modeled will sometimes not be able to meet Class II PSD increments for SO_2.
- Required separation distances between Class I PSD areas and power plants with 80 percent SO_2 removal and 99 percent particulate removal ranged from 5 to 75 miles.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

- At some sites, removing only the percentages of SO_2 and particulates required to meet the existing federal NSPS for coal-fired power plants can result in violations of ambient air and PSD standards.

- *Very high levels of particulate removal (99.3-99.8 percent) will usually be required for power plants to meet the 20-percent plume opacity NSPS for electric power plants.*

- *State NSPS in Wyoming and Montana may require the greatest percentage of SO_2 removal of any applicable standards in those states.*

3.2.1 Introduction

Air quality impacts can vary significantly depending on the choice of energy resource development technology and where it is located. This section summarizes the major conclusions regarding air impacts of western energy development, based on the analysis for the six site specific scenarios and for the regional scenarios. The first subsection identifies the key technological variables while the next identifies important locational variables. The third subsection summarizes the findings regarding regional air impacts. The fourth section concludes with a summary of the technological and locational factors that can most significantly affect air quality impacts.

3.2.2 Variations by Technologies

The two technological factors that affect air quality impacts most significantly are the quantities of criteria pollutants[1] emitted and labor intensiveness. In the case of electric power generation, the extent to which emission control technologies are employed greatly affects emission quantities.

A. Emissions and Control Technologies

Some emission differences among technologies are basically independent of location and are almost entirely a function of the configuration of the technology. Not only are there choices among types of conversion facilities but, in the case of electric power plants, in air pollution environmental controls as well.[1]

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[1] "Criteria pollutants" refer to the six pollutants for which ambient air quality standards are set: SO_2, particulates, nitrogen dioxide (NO_2), CO, nonmethane HC, and photochemical oxidants. Although technically only nonmethane HC are covered, the more inclusive term "hydrocarbon" is generally used. The HC limits serve as a "guideline" for potential oxidant problems and are not interpreted by the Environmental Protection Agency as a rigid standard. Very little ozone and NO_2 are emitted; rather they are formed by chemical reactions in the atmosphere. The oxides of nitrogen (NO_x) occur in several molecular forms, generally designated NO_x. In measuring emissions (which are primarily nitric oxide [NO]) whatever combinations of NO_x occur are converted to NO_2 according to their molecular weights to allow comparison with NO_2 standards.

(1) Emissions

Table 3-4 presents criteria pollutant emissions data for energy facilities based on the range of conditions for the six site specific scenarios. Table 3-5 represents these emissions on equivalent energy basis for each conversion alternative. Data for the electric power plant in Table 3-4 assume that 99 percent of the particulates and 80 percent of the SO_2 are removed by emissions control technologies.[2] In general, this degree of control is required to meet ambient air standards in the eight-state study area. At several of our sites, a lower level of SO_2 control than this would meet NSPS[3] but a higher level would be required to meet PSD increments for Class II areas.[4]

On the basis of both the size facility deployed in our scenarios and equivalent energy, electric power plants with scrubbers emit more of four criteria pollutants (SO_2, particulates, NO_2 and CO) than any other type of conversion facility (Tables

---

[1] Emissions control is an integral part of the plant design for synthetic fuel technologies.

[2] These analyses assumed that sulfur was removed after coal combustion by scrubbers. However, the emissions would be the same for a given removal efficiency regardless of whether sulfur was removed prior to coal combustion (coal cleaning) or after coal combustion.

[3] In this report, NSPS refers to the emission standards in effect prior to the 1977 Clean Air Act Amendments, Pub. L. 95-95, 91 Stat. 685. According to the new legislation, emissions standards for new facilities must now be defined in terms of the best available system of continuous emission reduction. These newer, more stringent standards, which have not yet been defined by the Environmental Protection Agency, will be referred to as best available control technology.

[4] Current PSD requirements are based on an area classification system which divides the nation's "clean air" (i.e., areas where the air quality is better than that allowed by ambient air standards) into three classes. Each class permits progressively larger incremental additions (or "allowable increments") to concentrations of SO_2 and particulates. Class I areas are generally pristine, such as national parks, but states or Indian tribes may designate other areas as Class I. Class III areas permit deterioration to national ambient secondary standards.

TABLE 3-4: AIR EMISSIONS FOR STANDARD SIZE ENERGY FACILITIES^a (pounds per hour)

CONVERSION FACILITY	PARTICULATES	SO_2^{b}	NO_x	HC	CO
Coal					
Power Plant (3,000 MWe)^c	1,110 - 5,020	5,800-14,000	14,320-35,140	400 - 650	1,330 - 2,180
Lurgi Gasification (250 MMscfd)	N^d	520	650	47^d	N
Synthane Gasification (250 MMscfd)	8^d	3,520	5,050	94^d	180
Synthoil Liquefaction (100,000 bbl/day)^c	480 - 1,250^e	940-1,170	4,620-5,770	1,3[illegible] - 1,690	180 - 230
Surface Mine (12 MMtpy)	13 - 24	8-16	0.5-210	17 - 180	13 - 87
Oil Shale^f					
TOSCO II Oil Shale^f (50,000 bbl/day)	860	350	1,900	1,020	80
Underground Oil Shale Mine (26 MMtpy)	125	N	270	54	480
Modified *In Situ* Oil Shale Processing (57,000 bbl/day)	74	174	588	120	84
Modified *In Situ* Oil Shale Processing^g with Surface Retort (57,000 bbl/day)	362	343	1,777	130	U
Crude Oil					
Conventional Oil Extraction (50,000 bbl/day)	0.3	21.7	17.6	4.3	1.3
Enhanced Oil Extraction Steam Injection (100,000 bbl/day)	358-1,187	10,125	308	108	208
Enhanced Oil Extraction CO_2 Miscible (100,000 bbl/day)	120	3,420	1,040	35	70
Natural Gas					
Natural Gas Production/Processing (250 MMscfd)	2	468	655	1,000	2
Uranium					
Underground Mine (1,100 mtpd ore)	0.16	0.36	5	0.5	3
Surface Mine (1,100 mtpd ore)	361	8.9	123	U	93.4
Mill (1,000 mt yellowcake per year)	40	1.03	0.3	0.05	U
Solutional Mine-Mill (250 tons yellowcake per year)^h	N	N	N	N	N
Geothermal (100 MWe)	NA	210^i	NA	NA	NA

SO_2 = sulfur dioxide
NO_x = oxides of nitrogen
HC = hydrocarbons
CO = carbon monoxide
MWe = megawatt-electric
MMscfd = million standard cubic feet per day
N = negligible

bbl/day = barrels per day
MMtpy = million tons per year
U = unknown
CO_2 = carbon dioxide
mtpd = metric tons per day
mt = metric ton
NA = not applicable

TABLE 3-4: (continued)

[a] These numbers represent the range of emissions found in the site-specific scenarios; and facilities are assumed to be operating at a full load.

[b] Had scrubbers not been hypothesized for the power plants, these numbers would be about five times larger.

[c] 99 percent particulate removal and 80 percent SO_2 removal.

[d] These values do not include fugitive particulates or fugitive HC.

[e] This value does not include fugitive particulates.

[f] No range is available for oil shale because the processes were hypothesized at only one site.

[g] Assumes mined-out shale is processed by surface retorting facility.

[h] Emissions from the solutional uranium mine mill consist of ammonium, ammonium chloride, and uranium oxide.

[i] This number is for hydrogen sulfide (H_2S) and assumes 90 percent H_2S removal.

TABLE 3-5: AIR EMISSIONS ON AN EQUIVALENT ENERGY BASIS (pounds per 10^6 Btu in product)[a]

CONVERSION FACILITY	PARTICULATES	SO_2[b]	NO_x	HC	CO
Coal					
Power Plant[c]					
Btu (electric)	0.11 - 0.50	0.57 - 1.37	1.40 - 3.43	0.04 - 0.06	0.13 - 0.21
Btu (thermal	0.04 - 0.17	0.20 - 0.48	0.49 - 1.20	0.01 - 0.02	0.04 - 0.07
Lurgi Gasification	N	0.05	0.06	0.004	N
Synthane Gasification	0.001	0.34	0.48	0.01	0.02
Synthoil Liquefaction	0.02 - 0.05	0.04 - 0.05	0.20 - 0.25	0.06 - 0.07	0.01
Surface Mine	0.001	0.001	N - 0.01	0.001-0.008	0.001-0.004
Oil Shale[d]					
TOSCO II Oil Shale[d]	0.08	0.03	0.17	0.09	0.01
Underground Oil Shale Mine	0.006	N	0.01	0.003	0.02
Modified *In Situ* Oil Shale Processing	0.006	0.01	0.04	0.009	0.006
Modified *In Situ* Oil Shale Processing with Surface Retort[e]	0.03	0.03	0.14	0.01	U
Crude Oil					
Conventional Crude Oil Extraction	N	0.002	0.001	N	N
Enhanced Crude Oil Extraction Steam Injection	0.02 - 0.05	0.5	0.01	0.005	0.01
Enhanced Crude Oil Extraction CO_2 Miscible	0.005	0.15	0.04	0.001	0.003
Natural Gas					
Natural Gas Production/ Extraction	N	0.05	0.07	0.10	N
Uranium					
Underground Mine	N	N	0.0001	N	N
Surface Mine	0.01	0.0003	0.004	U	0.003
Mill	0.001	N	N	N	N
Solutional Mine-Mill[f]	N	N	N	N	N
Geothermal					
Btu (electric)	NA	0.61[g]	NA	NA	NA
Btu (thermal)	NA	0.21[g]	NA	NA	NA

Btu = British thermal units
SO_2 = sulfur dioxide
NO_x = oxides of nitrogen

HC = hydrocarbons
CO = carbon monoxide
N = negligible

U = unknown
CO_2 = carbon dioxide
NA = not applicable

TABLE 3-5: (continued)

[a] These numbers represent the range of emissions found in the site-specific scenarios; and facilities are assumed to be operating at a full load. Equivalent energy values are based on the Btu/year for the standard size for each facility. These are, in Btu/year: power plant, 6.73 X 10^{13} (Btu electric), 1.92 X 10^{14} (Btu thermal); gasification processes and natural gas, 8.21 X 10^{13} ; liquefaction, 1.84 X 10^{14} ; TOSCO II oil shale, 8.87 X 10^{13} ; *in situ* oil shale, 1.01 X 10^{14} ; conventional crude oil, 9.198 X 10^{13} ; underground oil shale mine, 1.67 X 10^{14} ; uranium mine-mill, 2.99 X 10^{16} ; coal mine, 1.92 X 10^{14} ; geothermal, 2.24 X 10^{12} (Btu electric), 6.4 X 10^{12} (Btu thermal).

[b] Had scrubbers not been hypothesized for the power plants, these numbers would be about five times larger.

[c] 99 percent particulate removal and 80 percent SO_2 removal.

[d] No range is available for oil shale because the processes were hypothesized at only one site.

[e] Assumes mined-out shale is processed by surface retorting facility.

[f] Emissions from the solutional uranium mine-mill consist of ammonium, ammonium chloride, and uranium oxide.

[g] This number is for hydrogen sulfide (H_2S) and assumes 90 percent H_2S removal.

3-4 and 3-5).[1] Coal gasification plants emit fewer pollutants than electric plants in all categories, and Synthoil liquefaction produces more HC emissions than other coal and oil shale synfuels facilities of the size deployed in our scenarios.

The results of our impact analyses indicate that fugitive HC emissions from liquid processing facilities (above-ground oil shale retorting and coal liquefaction) and from natural gas production can be expected to result in ambient HC concentrations that greatly exceed the federal 3-hour standard of 160 micrograms per cubic meter ($\mu g/m^3$). Because they are emitted at or near ground level, the total amount of fugitive HC emitted need not be large to produce the high concentrations often associated with these facilities. Leaks in valves and fittings and from fuel oil storage tanks account for most fugitive HC emissions. The highest concentrations are expected to be produced by above-ground oil shale retorting (up to 38,500 $\mu g/m^3$), followed by coal liquefaction (17,300-25,100 $\mu g/m^3$) and natural gas production (1,000 $\mu g/m^3$). Conventionally produced natural gas affects short-term ambient levels of HC more than the Lurgi and Synthane coal gasification processes (which range from 47 to 94 $\mu g/m^3$). However, these short-term violations of the HC standard are not expected to block development since the HC standard is interpreted by the Environmental Protection Agency (EPA) as a "guideline" for assessing potential oxidant problems rather than as a rigidly enforced maximum.

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[1] To provide a basis for comparing power plants with synthetic fuel plants, emissions are expressed on both an electrical output basis, and a per British thermal unit (Btu) of thermal input to the plant basis. However, comparing electrical energy to energy in oil or gas can be misleading since electricity has high quality uses not possible with oil and gas (such as electric home appliances and lighting). Hence, if electricity were used only for high quality demands, it would be worth about three times as much as thermal energy in oil and gas. Only about half of electricity is used this way, however, and the remainder is used for heat, for which a direct comparison with oil and gas can be justified. Numerically, on a Btu thermal basis, electricity is valued as the energy content of the coal which feeds the power plant. On a Btu-electrical basis, the electricity is valued by the energy content of the electrical energy. In the power plant, the energy produced when measured in Btu-electrical is about three times less than the energy as measured in Btu-thermal. Neither measure is exactly comparable to the energy content of oil or gas. A Btu-electrical is more valuable than a Btu of oil and gas; but a Btu-thermal in the power plant case is less valuable than oil and gas made from coal.

(2) The Effect of Control Technologies on Emissions from Power Plants

Under the Best Available Control Technology (BACT) provisions of the 1977 Clean Air Act Amendments, some percentage sulfur reduction will be required on all newly constructed power plants, which practically means that flue gas scrubbers will probably be required. Power plants without SO_2 scrubbers will emit about five times more SO_2 than indicated in Table 3-4.[1] Without a BACT requirement, NSPS could be met without scrubbers at some locations due to the low sulfur content of the coal (Kaiparowits/Escalante, Rifle, and Gillette).[2] However, our analyses of impacts at these sites indicate that at least one federal ambient SO_2 standard could be violated.[3] Further, at the three other sites (Farmington, Colstrip, and Beulah), plants equipped with scrubbers that remove only enough SO_2 to meet NSPS will exceed at least one federal and some state standards. In addition, plumes at all sites will generally not meet the 20 percent opacity standard without a very high level of particulate removal (99.3-99.8 percent).

(3) Emission Levels and PSD Requirements

Our site specific analyses indicate that coal gasification and liquefaction plants can meet all Class II PSD increments in these locations. However, oil shale retorts and power plants (with 80 percent efficient SO_2 scrubbers and 99 percent efficient particulate controls) may cause Class II increments to be exceeded locally and Class I increments to be exceeded in nearby national parks. In three of the locations (Kaiparowits/Escalante, Rifle, and Beulah), power plants exceed either one or both of the Class II 24-hour particulate and SO_2 increments.

Allowable increments for Class I areas apply to all new sources whether located within or outside the Class I area. This effectively establishes a "buffer zone" around Class I areas within which new facilities cannot be sited since pollutants from the facility must be diluted by atmospheric mixing to achieve the low concentrations allowed. The distance required for this dilution to take place determines the size of the "buffer zone," which varies by facility type, size, the effectiveness of emission controls, and local topographical and meteorological conditions. In this study, the distance from Class I PSD areas that facilities must be sited ranges from 5 to 75 miles. By far, the largest distance is required for electric power plants,[1] an average of about 52 miles. Distances required for Lurgi, Synthane, and Synthoil are roughly equivalent, ranging from 9 to 14 miles. The most restrictive standard for all conversion technologies is either the 3- or 24-hour SO_2 increment. Buffer zones are a siting consideration only in areas where there are numerous Class I PSD areas.

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[1] The values in Table 3-4 assume 80 percent SO_2 removal.

[2] The NSPS standard for SO_2 for large power plants is 1.2 lbs. of SO_2 per million Btu's of fuel burned.

[3] All the above conclusions are based on dispersion modeling results that are inherently approximate. The accuracy of the Gaussian-type dispersion models used in this study is generally accepted to be ±100 percent. However, evidence is beginning to accumulate that the models may be as accurate as ±50 percent.

(4) Pollution Control Alternatives

The effect on ambient air concentrations of SO_2 by power plants equipped with scrubbers with different efficiencies and stack heights is illustrated in Table 3-6. When the base case assumptions (80 percent SO_2 removal and 500 foot stack height) are used, three plants (Rifle, Beulah, and Kaiparowits/Escalante) will violate at least one federal Class II PSD standard for SO_2.[2] If 95 percent efficient scrubbers are used, no federal standards will be violated by any of the plants (assuming a 500 foot stack height). If a 1,000 foot stack height is assumed (with an 80 percent efficient SO_2 scrubber), none of the power plants will fail to meet Class II PSD increments for SO_2 ambient air concentrations.

Other air pollution control alternatives considered include reduction of plant size and relocation of the plant site from complex to flat terrain. At Rifle, plant capacity would have to be reduced from 1,000 to 500 megawatt-electric (MWe) to meet applicable federal standards (with an 80 percent efficient SO_2 scrubber), but if moved to a site with flat terrain, the 1,000 MWe facility would meet those standards. Assuming 80 percent SO_2 removal and 500 foot stack height, the 3,000 MWe power plants at Beulah and Kaiparowits/Escalante could meet Class II PSD increments by reducing plant capacity to 1,500 and 500 MWe, respectively. The 3,000 MWe Escalante plant would meet applicable standards if moved to a site with a flat terrain.

In summary, the 80 percent efficient SO_2 scrubbers for power plants assumed in this study are predicted to meet federal Class II PSD standards at half of the six scenario locations. At two other sites the state standards will be more restrictive. For these three power plants which fail to meet PSD Class II standards for SO_2, compliance could be achieved with a 95 percent efficient

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[1] This assumes a 3,000 MWe power plant (except the Rifle plant is 1,000 MWe) with 80 percent SO_2 and 99 percent particulate removal.

[2] State standards would require additional emission controls on the facilities at Gillette and Colstrip.

TABLE 3-6: THE EFFECT ON AMBIENT AIR CONCENTRATIONS OF ALTERNATIVE SO_2 CONTROLS ON POWER PLANTS FOR THE SIX SITE-SPECIFIC SCENARIOS
(micrograms per cubic meter)

CLASS II PSD STANDARD FOR SO_2	MEASURING TIME INTERVAL	CONCENTRATIONS RESULTING FROM SO_2 SCRUBBER EFFICIENCIES AND STACK HEIGHTS			
		80% SO_2 REMOVAL 500-FOOT STACK	95% SO_2 REMOVAL 500-FOOT STACK	80% SO_2 REMOVAL 300-FOOT STACK	80% SO_2 REMOVAL 1,000-FOOT STACK
512	3-hour	229-1,060	57-265	280-2,043	104-365
91	24-hour	51-293	12-73	55-357	13-63
20	Annual	1.6-11.2	NC	NC	NC

SO_2 = sulfur dioxide
PSD = prevention of significant deterioration
NC = not calculated

SO_2 scrubber. Reduced plant size, utilizing 1,000 foot stacks, and relocating plant sites from complex to flat or elevated terrain are other alternatives which can reduce ambient air concentrations from energy conversion facilities. At the locations where scrubbers are not needed to meet NSPS because of the low sulfur content of the coal, at least one federal ambient SO_2 standard could be exceeded.

B. Labor Intensiveness

The second technological factor that significantly affects air quality impacts is the labor intensiveness of a technology. Our impact analyses indicate that peak ground-level concentrations of particulates, NO_2, and HC produced by energy related urban development can be higher than those produced by energy facilities themselves.[1] For example, based on our six site specific scenarios, annual particulate concentrations from urban sources ranged from 7 to 30 $\mu g/m^3$, which exceed those from the energy facilities (0.4-4.0 $\mu g/m^3$). These high concentrations result from the release of pollutants at or near ground level in urban areas by such sources as automobiles and home heating. Total emissions of pollutants in the urban area are small in comparison to those emitted by an energy conversion or production facility; in fact, less than 10 percent of the total pounds per year emitted come from urban sources. However, because pollutants from urban sources are released close to the ground, and thus experience little or no mixing and dilution, high ground-level concentrations result.

Table 3-7 summarizes the projections from our six site-specific scenarios for peak ground-level concentrations of pollutants originating from urban sources and from energy facilities in 1990. Note that the peak concentrations of particulates, NO_2, and HC produced by urban sources nearly always exceed those from the energy facility.

The models used to estimate air impacts also suggest that these concentrations are not likely to increase consistently as urban population increases, but rather to increase rapidly as the total urban population rises to about 15 to 20 thousand

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[1] See Section 3.4 for details on the increases in population that can be attributed to energy resource development

TABLE 3-7: A COMPARISON OF PREDICTED PEAK GROUND-LEVEL CONCENTRATIONS OF POLLUTANTS FROM URBAN SOURCES AND POWER PLANTS FOR THE SIX SITE-SPECIFIC SCENARIOS, 1990[a]
(micrograms per cubic meter)

POLLUTANT	STANDARD[b]	KAIPAROWITS/ESCALANTE			FARMINGTON		RIFLE		GILLETTE		COLSTRIP		BEULAH	
		URBAN	KAIPAROWITS POWER PLANT	ESCALANTE POWER PLANT	URBAN	FACILITY	URBAN	POWER PLANT	URBAN	FACILITY	URBAN	FACILITY	URBAN	FACILITY
SO_2														
Annual	80	8	4.4	11.2	16	3.3	10	2.3	14	1.6	5	2.7	4	1.8
24 hour	365	27	51.0	293.0	54	84.0	34	155.0	48	51.0	17	90.0	14	112.0
3 hour	1300	48	229.0	1,060.0	96	459.0	60	530.0	84	323.0	30	657.0	24	692.0
Particulate														
Annual	60	16	1.6	4.0	30	1.8	20	0.4	27	.4	10	.5	7	1.4
24 hour	160	54	18.0	105.0	102	67.0	68	30.0	92	19.0	34	23.0	24	26.0
NO_2[c]														
Annual	100	26	11-18	29-49	48	6.5-11	NC	5.7-9.5	41	4.6-7.7	16	3.6-6.0	11	12-14
HC														
3 hour	160	481	46.0	58.0	871	78.0	571	33.0	780	78.0	270	69.0	180	50.0

SO_2 = sulfur dioxide
NO_2 = nitrogen dioxide
NC = not calculated
HC = hydrocarbons

[a] The data displayed in this table are taken from Chapters 4-9, and are for power plant/mine combinations. The data from both urban sources and from power plant/mine combinations represent peak (not average) concentrations.

[b] The most stringent of either the primary or secondary national ambient air quality standard is listed here. Each of the scenario chapters (4-9) lists both primary and secondary standards.

[c] Estimates of NO_2 concentrations at facilities were based on the assumption that all oxides of nitrogen (NO_x) would be converted to NO_2. For urban concentrations, it was assumed that 50 percent of the NO_x would be converted to NO_2. Range indicates 0 to 40 percent removal of NO_x by scrubber.

people and at a progressively slower rate thereafter.[1] Thus, small or new towns in the West are likely to experience a high percentage increase in ambient pollutant levels as population increases, while larger towns (such as Farmington) will experience relatively little change.

C. Other Technology-Related Impacts

Other air impacts analyzed included long-range visibility, cooling tower fogging and icing, cooling tower salt deposition, fine particulates, oxidants, and weather modification. Of these, visibility reduction appears to be the most significant problem area. Visibility reductions due strictly to sulfate formation were examined for each of the six sites. Based on a conversion rate of SO_2 to sulfates of one percent per hour, visibility during a worst-case meteorological episode could be reduced downwind of an energy facility from present values of 60-70 miles to 8-60 miles. The greatest visibility reductions are associated with power plants. These worst-case conditions are expected to occur from one to a few times per year.

Energy development could also produce oxidant (i.e., smog) problems. Background or emitted HC, in combination with NO_x in plumes, provides the potential for oxidants downwind of a facility. As indicated previously, several of the technologies emit relatively large amounts of HC, NO_x, or both. However, the seriousness of the problem is unknown since present knowledge of the conversion processes forming oxidants is insufficient to predict concentrations based on residuals emissions.

3.2.3 Variations in Existing Conditions

Air quality impacts can vary widely in the eight-state study area due to variations in existing conditions. Many of these existing conditions are geographical or meteorological in nature, such as rugged terrain, poor dispersion potential, and the proximity of resources or sites to Class I areas. Other existing conditions affecting air quality include characteristics of the coals found in different locations, the size of communities located in the vicinity of the resource development, current ambient air quality, and state air quality standards.

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[1] Projected concentrations from urban sources are derived from both emission rates and dispersion potential. The projection that peak concentrations increase rapidly up to a point (15-20 thousand people) and progressively slower thereafter is based on several important and debatable assumptions. First, emission rates from urban sources are assumed to be directly (or linearly) proportional to the number of people in the town. Secondly, the population densities of different-size towns are assumed to remain relatively constant. Thus, since urban emission concentrations are measured at a point in the center of town, pollution sources more than 1 or 2 miles from the center will have little effect on concentrations measured there. For towns larger than 15-20 thousand, it is assumed that new pollutant sources will be located increasingly further from the center of town and thus have only marginal impact on concentration levels.

A. Coal Characteristics

Although low sulfur is an advantage commonly attributed to western coals, many western coals also have low heating values. The sulfur content of the coals used in our analyses range from 0.5 to 1.0 percent by weight and heating values range from 6,950 to 11,300 British thermal units (Btu's) per pound. As a result of these variances, sulfur emissions on a per-million Btu's basis are not necessarily low. Assuming that 100 percent of the sulfur in the coal is converted to SO_2, the Kaiparowits, Rifle, and Gillette coals meet the NSPS of 1.2 pounds of SO_2 emitted for every one million Btu's of coal burned. For the other coals to meet the NSPS standard, only 52-73 percent of the sulfur could be converted to SO_2 in the boiler; that is, 27-48 percent of the sulfur would have to be retained in the ash. However, sulfur retention in the ash of more than 20 percent is not usual.

B. Terrain and Dispersion Potential

Another significant existing condition influencing air quality in the eight-state area is terrain, most notably the complex terrain found in western Colorado and southern Utah. Our impact analyses suggest that the complex terrain in southern Utah can contribute to high ground-level concentrations of pollution as a consequence of plume impaction. In northwestern Colorado, ambient levels of SO_2 are predicted to exceed Colorado's ambient standard (3-hour average) when the plume from the 50,000 barrel per day (bbl/day) TOSCO II oil shale plant impacts on the rugged terrain features in the area. These SO_2 violations are likely to occur less than 30 percent of the time. In the Kaiparowits/Escalante area, predicted ambient levels produced by plume impaction approach but do not exceed ambient standards.[1]

At our other site-specific scenario locations, the terrain is less rugged and plume impaction does not normally occur. In these cases, increased concentrations are predicted to result from other conditions such as plume looping and limited vertical mixing.[1]

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[1] These results were obtained using a modified Gaussian air dispersion model. Although other routines, such as potential flow models, have been used to project impacts in rough terrain, no consensus exists regarding the most appropriate model. However, the modifications made in this analysis were designed to account for previous limitations of Gaussian-type models in rough terrain.

Dispersion meteorology is variable over the eight-state area. By itself, poor dispersion does not cause violation of standards at any one site. However, when combined with other factors, such as complex terrain, it can exacerbate what already may be a problem.

An overview of the effect of site specific variations is presented in Table 3-8. This table shows the level of control required for power plants to meet all SO_2 standards at our six sites. To meet all federal ambient air SO_2 standards, Class II SO_2 increments, and applicable state standards, 78-96.2 percent of the SO_2 would have to be removed. The specific requirement depends on the site. Due to Colorado's strict SO_2 standards, any facility located in that state will require the removal of more SO_2 than in any of the other states. A higher percentage of SO_2 removal is required to meet Colorado's standard than to meet federal Class II PSD increments. The Montana Air Quality Bureau determines the SO_2 removal required according to that state's NSPS. In Wyoming the state NSPS for power plants is the most restrictive for SO_2 emissions. In the other three states the federal Class II PSD (24-hour and 3-hour) increments are the most restrictive.

C. Other Site Specific Variations

Two other factors that vary by site can exacerbate air quality problems: the size of the community in which the facility is located, and the proximity of a facility to potential Class I PSD areas. As noted previously, the relative change in air quality will be greater when a facility is located in a small community than when it is located in a large town. As a result, in sparsely populated areas such as southern Utah, the change in air quality will be relatively greater even though the absolute level of ambient concentrations may be the same as in more densely populated areas.

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[1] Plume looping (i.e., when plumes sink to the earth, flow up and down, or roll in response to breezes, air currents, or eddies in the area) occurs during periods of light wind speeds of 3-5 knots and strong incoming solar radiation (summertime, midday, clear sky). Large thermal eddies cause plumes to assume a rolling configuration thus transporting undiluted plume segments rapidly to ground level. Limited mixing occurs when a strong inversion exists slightly above the plume height and stops the upward mixing of the plume. The plume is constrained vertically between this "lid" and the ground.

TABLE 3-8: SULFUR REMOVAL EFFICIENCIES REQUIRED FOR COAL-FIRED POWER PLANTS TO MEET ALL FEDERAL AND STATE SULFUR DIOXIDE STANDARDS

STATE	SULFUR REMOVAL REQUIRED (%)	GOVERNING REGULATION
Colorado Rifle 1,000 MWe and Mine	96.2	State Category II Ambient
Montana Colstrip 3,000 MWe and Mine	(State NSPS maximum control capability technically practicable and economically feasible as determined by Air Quality Bureau); or 80	Federal 24 hr. Class II PSD
North Dakota Beulah 3,000 MWe and Mine	85	Federal 24 hr. Class II PSD
New Mexico Farmington 3,000 MWe and Mine	78	Federal 24 hr. Class II PSD
Utah Escalante 3,000 MWe and Mine	94	Federal 24 hr. Class II PSD
Wyoming Gillette 3,000 MWe and Mine	82	State NSPS

SO_2 = sulfur dioxide
MWe = megawatt-electric
NSPS = New Source Performance Standards
hr. = hour
PSD = prevention of significant deterioration

Class I PSD areas (such as national parks) may present some problems where they are widespread or occupy large amounts of land (as in southern Utah), but very few are located in the coal regions of the Northern Great Plains. Proximity to Class I PSD areas will make development siting more difficult, particularly in the case of electric power plants where large buffer zones are required.

3.2.4 Regional Impacts

Air quality impacts for the region are dependent on the existing air quality and meteorological conditions as well as the overall level of energy development.

The existing ambient air quality in the study area appears to be good when considered on the basis of annual averages. However, due to windblown dust, the federal 24-hour primary standard for particulates is periodically violated. Also short-term oxidant and HC concentrations, apparently from natural sources, approach federal standards. Geographically, the southeastern part of the study area has the best pollutant dispersion potential because of typically high mixing depths and high wind speeds. The sharp terrain differences in the Rocky Mountain area can cause wintertime air stagnation and thus dispersion problems. The Northern Great Plains area, in contrast, has much less air stagnation because of higher winds and less rugged terrain.

Table 3-9 gives the projected emissions from the energy facilities and associated population for the Northern Great Plains subregion (Wyoming, Montana, and North Dakota) and the Rocky Mountain subregion (Colorado, Utah, and New Mexico). These emission levels are based on the Low Demand scenario for the year 2000. Emissions in tons per year of the four criteria pollutants are shown as well as the increases above the 1975 levels due to energy development. Except for HC, emissions associated with the population are only 0.7-3.2 percent of those associated with the energy facilities. The population related HC emissions are due primarily to motor vehicles.

Overall, emission levels in the Northern Great Plains are projected to be higher than in the Rocky Mountain Region. This is due primarily to the scenario projection that more coal fired power plants will be sited in the Northern Great Plains than in the Rocky Mountain states. In the Northern Great Plains, the largest increase above the 1975 level is NO_x which is predicted to be 4.73-6.47 times greater in the year 2000. The range in NO_x emissions results from the uncertainty associated with how much NO_x will be removed by scrubbers; a range of 0 to 40 percent removal is assumed. Increases in the Rocky Mountain Region range from 1.02 (HC) to 1.36-1.51 (NO_x) times the 1975 levels.

TABLE 3-9: PROJECTED EMISSIONS IN 2000 FOR THE NORTHERN GREAT PLAINS AND ROCKY MOUNTAIN REGIONS: LOW DEMAND SCENARIO (thousands of tons per year)

REGION	PARTICULATES	SULFUR DIOXIDE	OXIDES OF NITROGEN	HYDROCARBONS
Northern Great Plains				
Emissions in 1975	471	1,123	338	438
Emissions projected: 2000				
Energy facilities	124.9	788.7	1,221.5-1,809.3	43.8
Population	1.0	5.2	39.2	48.0
Total and increase above 1975[a]	596.9 (1.27)	1,916.9 (1.71)	1,598.7-2,186.5 (4.73-6.47)	529.8 (1.21)
Rocky Mountain				
Emissions in 1975	414	712	472	489
Emissions projected: 2000				
Energy facilities	43.4	65.7	159.1-231.7	-1.7[b]
Population	0.3	1.5	11.1	13.6
Total and increase above 1975[a]	457.7 (1.11)	779.2 (1.09)	642.2-714.7 (1.36-1.51)	500.9 (1.02)

[a] The increase above 1975 (obtained by dividing the total by the 1975 value) is given in parentheses.

[b] This number is negative because oil and natural gas production declines from the 1975 level.

Emissions from the energy facilities disaggregated by state are given in Table 3-10. As in the analysis of subregions, the cause of the relatively high emissions in North Dakota, Montana, and Wyoming is the large numbers of coal fired power plants sited there. The largest relative increases above 1975 levels for all pollutants except HC are in North Dakota. These range from 1.69 (particulates) to 8.41 (NO_x) times the 1975 emissions. Montana is projected to have the largest total emissions of particulates, SO_2, and HC. Utah shows essentially no change from the 1975 level because the only new energy facilities in the Low Demand case scenario for Utah are two uranium mines and mills.

3.2.5 Summary of Technological and Locational Factors

This summary identifies technology-location combinations that cause critical air quality problems. By so doing, it also suggests combinations that could mitigate these problems. The problems that can arise because of technology-location combinations are identified in Table 3-11. The table also indicates the technological and locational factors that cause the problem. Note that the most critical problems are caused by either electric power plants or oil shale retorting facilities (above-ground).

In some locations in the West, NSPS (generally the least restrictive federal standards for conditions in the eight-state area) cannot be met by electric power plants without scrubbers. This problem is a consequence of the heat and sulfur contents of the coal.

At some locations, 80-percent efficient scrubbers on power plants of the size modeled will not be adequate to meet the most restrictive ambient air quality standards. The existing ambient air quality, dispersion potential, terrain characteristics, and tight state standards make it particularly difficult to meet all standards in southern Utah, Colorado, North Dakota, and Montana. To overcome this problem, Class II PSD increments would have to be relaxed, scrubbers with a higher removal efficiency would have to be employed, smaller plants would have to be built, or the coal would have to be exported for conversion elsewhere.

Terrain characteristics in southern Utah and western Colorado are such that regular violation of several federal ambient air standards would occur as a result of emissions from power plants and from oil shale retorting facilities if the projected type and level of development occurs. Mitigation will require very high levels of pollution control or exporting the coal.

The labor intensity of conversion facilities, particularly the operating labor requirements of synthetic fuels facilities, results in greater ambient concentrations of particulates, NO_2, and HC being caused by urban sources than by the energy facilities. If the community in which development takes place is small (e.g.,

TABLE 3-10: PROJECTED EMISSIONS IN SIX WESTERN STATES: LOW DEMAND SCENARIO[a]
(thousands of tons per year)

	PARTICULATES	SO_2	NO_x	HC
Colorado: 1975	222	54.2	163	213
Increase: 2000	22.1	37.4	127.5	35.7
Total: 2000	244.1 (1.10)	91.6 (1.70)	290.5 (1.78)	248.7 (1.16)
New Mexico: 1975	113	490	220	168
Increase: 2000	21.0	28.3	68.0	-37.5[b]
Total: 2000	134.0 (1.18)	518.3 (1.06)	288.0 (1.31)	130.5 (.77)
Utah: 1975	79	168	89	108
Increase: 2000	0.3	N	N	N
Total: 2000	79.3 (1.0)	168.0 (1.0)	89 (1.0)	108 (1.0)
Wyoming: 1975	83.1	76.5	80	61
Increase: 2000	17.6	107.0	282.1	11.0
Total: 2000	100.7 (1.21)	183.5 (2.40)	362.1 (4.52)	72.0 (1.18)
Montana: 1975	301	960	164	300
Increase: 2000	48.0	305.3	533.2	16.4
Total: 2000	349.0 (1.16)	1,265.3 (1.32)	697.2 (4.25)	316.4 (1.05)
North Dakota: 1975	87.1	86.6	94.5	77.5
Increase: 2000	59.7	376.4	700.1	16.4
Total: 2000	146.8 (1.69)	463.0 (5.34)	794.6 (8.41)	93.9 (1.21)

SO_2 = sulfur dioxide
NO_x = oxides of nitrogen
HC = hydrocarbons
N = negligible

[a] The numbers in parentheses represent the fractional increase (or decrease) in the year 2000 relative to 1975 levels; i.e., they are the 2000 levels divided by the 1975 levels.

[b] This number is negative because HC emissions decline through the year 2000. The increased HC emissions from synthetic fuel facilities are more than offset by declines in crude oil and natural gas production.

TABLE 3-11: SUMMARY OF AIR QUALITY PROBLEMS

AIR QUALITY PROBLEMS	COMBINATIONS OF FACTORS THAT CAUSE THE PROBLEM	
	TECHNOLOGICAL FACTORS	LOCATIONAL FACTORS
Violations of federal New Source Performance Standards as well as other standards in Farmington, Colstrip, and Beulah areas	Emissions from power plants without scrubbers	Sulfur content and heating value of the coal
Violations of Class II PSD standards (especially in southern Utah, Colorado, and North Dakota)	Emissions from power plants with 80% efficient scrubbers	Existing ambient air quality, dispersion potential, and terrain
Regular violation of ambient standards, especially in southern Utah and Colorado	Emissions from power plants with scrubbers and oil shale processing facilities	Rough terrain
Requirements for strict SO_2 control in Colorado and possibly Montana, and strict SO_2 and NO_x control in North Dakota	Emissions from power plants with scrubbers and oil shale processing facilities	State air standards
Potential siting problems, especially in Utah and Colorado, due to separation distances from Class I areas that are necessary	Emissions from conversion facilities, especially power plants	Proximity to Class I areas (e.g., national parks and forests)
Larger concentrations of several pollutants produced by urban sources than by facilities. Largest relative increase for towns under 15,000	Labor intensiveness, which is especially large for synthetic fuels technologies	Community size

PSD = Prevention of Significant Deterioration
SO_2 = sulfur dioxide
NO_x = oxides of nitrogen

most communities in southern Utah), the percent change in ambient air quality as a result of urban sources will be great.

In general, this summary suggests that facilities in Wyoming and New Mexico are likely to have the fewest air quality problems. In these states, applicable federal and state standards can be met with the least percentage removal of SO_2 and particulates by emission control technologies. Montana might also be included in this group except for the uncertainty of how the state NSPS may be interpreted. But in no case can all standards be met with the size facilities projected without the use of some emission control, specifically scrubbers for SO_2 control.

Facilities located in southern Utah and western Colorado will present the greatest problems unless removal percentages are quite high. In Colorado, this is largely due to state SO_2 standards and, to some extent, the terrain in the oil shale area of western Colorado. Southern Utah appears to have the most restrictive combination of factors affecting air quality: a combination of poor dispersion potential, complex terrain, and Class I areas that are in close proximity to development sites that make it necessary for facilities located here to install the most efficient emission controls.

3.3. WATER AVAILABILITY AND QUALITY

HIGHLIGHTS

- **CRITICAL FACTORS**

  - *Four factors that vary among technologies[1] can significantly affect water impacts: water requirements; labor intensity; amount and composition of effluents from facilities and from energy-related population increases; the disruption of aquifers; and the design and operation of holding ponds for effluents from conversion facilities;*

  - *Six locational factors can also significantly affect these impacts: water availability; water quality; coal characteristics; climate; aquifer characteristics; and the capacity of municipal wastewater treatment facilities.*

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[1] The conversion technologies considered include coal-fired electric power plants, Lurgi and Synthane gasification, Synthoil liquefaction, TOSCO II oil shale retorting, in situ oil shale retorting, and geothermal electric power production. Slurry pipelines were also considered.

WATER REQUIREMENTS

- If wet cooling is used, electric power plants require more water than any other conversion technology examined.
- Synthoil liquefaction requires less water than any other coal synfuel technology.
- Cooling aacounts for 45 to 95 percent of the total water requirements of coal conversion technologies (not including water needed for mining the coal).
- Water requirements for energy-related population increases are, on the average, one-tenth that for conversion facilities.

- Water requirements for energy-related population increases are, on the average, one-tenth that for conversion facilities.

WATER AVAILABILITY

- Less water for energy development is available in the Upper Colorado River Basin (UCRB) than in the Upper Missouri River Basin (UMRB); unquantified federal and Indian water rights, the status of unused allocated rights, and other questions make the availability of water uncertain in both basins.
- By the year 2000, a low-development scenario would require 12-15 percent of the surface water not presently being used in the UCRB; a high-demand scenario would require 59-64 percent.
- Water consumption for cooling by electric power plants could be reduced by 70-79 percent if a combination of wet and dry rather than wet cooling were used.
- Water consumption varies significantly by location for the same coal conversion technology.

EFFLUENTS

- The quantity and composition of effluents from the coal conversion plants vary with location. For a given process, the quantity of waste effluents varies by a factor of four or five depending upon location.
- The ash and sulfur content of coal are largely responsible for the site variation in the quantity of waste effluents; the highest ash coals are found in the Southwest.

- *Surface oil shale residuals exceed those from coal conversion by an order of magnitude; the primary residual is spent shale. Residuals from modified in situ oil shale processing with a surface retort are at least twice as large as those from power plants and three times as large as those from coal synfuels.*

- *Discharging effluents into evaporative ponds poses a potentially significant surface and groundwater quality problem.*

3.3.1 Introduction

Factors that cause water impacts and vary by technology are: the water requirements of the technology and the associated increase in population; effluents from energy facilities and domestic sewage treatment plants; aquifer disruption; and the design and maintenance of holding ponds. The severity of impacts that result from these factors depends on site-specific factors such as water availability, coal characteristics, climate, aquifer characteristics, existing water quality, and the capacity of municipal wastewater treatment facilities. This section describes the extent to which these factors vary among technologies and sites and the extent to which these variations affect impacts.

3.3.2 Variations Among Technologies

Technology-specific factors are discussed in three categories: water requirements; water effluents; and aquifer disruption.

A. Water Requirements

Water requirements are discussed under the following headings: water requirements of energy facilities; the effect of variations in the proportions of wet and dry cooling on water requirements; and the effect of labor intensity on water requirements.

(1) Water Requirements of Energy Facilities

The two sets of water requirement estimates used for the energy development technologies are listed in Table 3-12. The Energy Resource Development Systems data are rough estimates based on a variety of government sources. The Water Purification Associates (WPA) data are based on detailed engineering analyses of the technologies where the objective of the analysis was to minimize water use.[1]

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[1] Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977. WPA's estimates are for the process design that would minimize water as long as economically feasible. It is technologically feasible to reduce water requirements further.

TABLE 3-12: WATER CONSUMPTION BY TECHNOLOGY
(wet cooling)

TECHNOLOGY	SIZE[c]	ERDS[a]		WPA[b]	
		ACRE FEET PER YEAR	GALLONS PER 10^6 BTU IN PRODUCT[d]	ACRE FEET PER YEAR	GALLONS PER 10^6 BTU IN PRODUCT
Coal[e]					
Power Plant	3,000 MWe	29,400		23,880-29,820	
Per Btu electric[f]			107		87-108
Per Btu thermal[f]			37		30-39
Lurgi Gasification[g]	250 MMscfd	6,710	24	4,890-7,130	17-25
Synthane Gasification[g]	250 MMscfd	9,090	32	7,670-8,670	27-31
Synthoil Liquefaction[h]	100,000 bbl/day	17,460	27	9,230-11,750	14-18
Surface Mine[i]	12 MMtpy	3,060	5	NC	NC
Slurry Pipeline[j]	25 MMtpy	18,390	14	19,171	15
Oil Shale					
TOSCO II Oil Shale Mine-Retort[h]	50,000 bbl/day	9,272[k]	31	NC	NC
Modified *In Situ* Oil Shale Processing[h]	57,000 bbl/day	4,360[l]	13	NC	NC
Modified *In Situ* Oil Shale Processing *with* Surface Retort[h]	57,000 bbl/day	5,663[m]	16	NC	NC
Oil					
Conventional Crude Oil Extraction	50,000 bbl/day	2,500-4,100[n]	9-13	NC	NC
Enhanced Crude Oil Extraction	100,000 bbl/day				
Steam Flooding[o]		4,000-24,000	7-42	NC	NC
CO_2 Flooding[o]		28,000-60,000	50-100	NC	NC
Gas					
Natural Gas Wells	250 MMscfd	380	1.4	NC	NC
Uranium					
Underground Mine	1,100 mtpd (ore)	20	0.02	NC	NC
Surface Mine (open pit)	1,100 mtpd (ore)	40-50	0.04-0.05	NC	NC
Mill	1,000 mtpd (yellowcake)	250	0.27	NC	NC
Solutional Mine-Mill	250 tpy (yellowcake)	200	0.87	NC	NC
Geothermal[p]	100 MWe	12,700-13,700		NC	NC
Btu electric[f]			1,384-1,493		
Btu thermal[f]			485-523		

TABLE 3-12: (Continued)

ERDS = Energy Resource Development Systems
WPA = Water Purification Associates
BTU = British thermal unit
MWe = megawatt-electric
MMscfd = million standard cubic feet per day
bbl/day = barrels per day

MMtpy = million tons per year
NC = not considered
CO_2 = carbon dioxide
mtpd = metric tons per day
tpy = tons per year

[a] The ERDS or Energy Resource Development Systems descriptions prepared for this study will be distributed separately. They are based on: University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Washington, D.C.: Government Printing Office, 1975; and Radian Corporation. A Western Regional Energy Development Study, 3 vols. and Executive Summary. Austin, Tex.: Radian Corporation, 1975.

[b] Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977.

[c] Load factors assumed as: 75 percent for coal and geothermal electric power; 90 percent for gasification, liquefaction, oil shale processing, oil, and gas; and 100 percent for slurry pipeline and uranium mine-mill.

[d] These values are calculated using the Btu's in the product per year for each facility: coal-fired power plant, $6.73X10^{13}$ Btu-electric and $1.92X10^{14}$ Btu-thermal; geothermal power plant, $2.24X10^{12}$ Btu-electric and $6.4X10^{12}$ Btu-thermal; liquefaction and enhanced oil extraction, $1.84X10^{14}$; gasification and natural gas $8.2125X10^{13}$; TOSCO II oil shale, $8.87X10^{13}$; modified in situ processing, $1.01X10^{14}$; coal mine, $1.92X10^{14}$; uranium mine-mill, $2.99X10^{14}$; solutional uranium mine-mill, $7.48X10^{13}$; slurry pipeline, $4.0X10^{14}$.

[e] No mining, reservoir evaporation, or reclamation requirements are included in the ERDS data for coal conversion facilities. WPA data include water for reclamation for areas with less than 10 inches annual precipitation.

[f] Per Btu thermal refers to the coal or the coal equivalent in the case of geothermal; per Btu electric refers to the electricity; 34 percent efficiency is assumed.

[g] The heating value of the product is assumed to be 950 Btu's per standard cubic feet.

[h] The heating value of the product is assumed to be $5.66X10^6$ Btu per barrel.

[i] This mine is of the size required by a 3,000 MWe power plant.

[j] 7,980 Btu's per pound.

[k] Of the total 9,272, 891 is for dust control in the mining operations, 7,301 is needed for the retort, and 1,100 is used for reclaiming and revegetating the spent shale.

[l] Of the total 4,360, 730 is for dust control in the mining operations and 3,630 is needed for the in situ retort.

[m] Of the total 5,663, 547 is for dust control in the mining operations, 2,722 is needed for the in situ retort and 2,081 for the surface retort, and 313 is used for reclaiming and revegetating the spent shale.

[n] This represents the water requirements for a water flood in the oil field.

[o] For the steam flood, 1-6 barrels of water per barrel of oil produced; for the CO_2 flood, 7-15 barrels of water per barrel of oil produced.

[p] This range represents one-stage and two-stage flash steam and binary cycle. It includes water evaporated by the cooling system and blowdown water.

Assuming the use of wet cooling, coal-fired electric power plants require more water than synthetic fuel technologies, both in terms of absolute water requirements, about 24,000 to 30,000 acre-feet per year (acre-ft/yr), and the amount of water required to produce one million Btu's of energy. Comparing both sets of estimates, water requirements for synthetic fuel facilities range from about 5,000 to 17,500 acre-ft/yr, with Synthoil liquefaction requiring the most (9,230 to 17,460 acre-ft/yr) and Lurgi requiring the least (4,890 to 7,130 acre-ft/yr). Note that minimizing water requirements in the design and operation of these facilities as discussed in the following section makes a significant difference in water consumption. In terms of gallons of water required to produce one million Btu's of synthetic fuel, Synthoil requires the least and Synthane gasification requires the most water. *In situ* oil shale retorting requires about half as much water as above ground retorting.

In comparison, a surface coal mine requires only about 5 gallons of water per million Btu's of coal mined (about 3,000 acre-ft/yr).[1] Some of the water requirements of coal mines can be met with water from mine dewatering operations. The water requirements of coal mining are about one-tenth of that required by coal-fired power plants. If coal is mined for export only, additional water requirements for coal export by slurry pipeline are significant (18,000-19,000 acre-ft/yr or 240-250 gallons per ton).

(2) The Effect of Wet/Dry Cooling on Water Requirements

As shown in Table 3-13, water for cooling represents 45.1-92.3 percent of the total water requirements of coal conversion facilities. With the exception of oil shale retorting, cooling is the largest single water user for energy conversion facilities.[2] Water requirements for three cooling alternatives were considered: all wet cooling (high wet cooling in Table 3-13), intermediate wet cooling, and minimum wet cooling. As indicated in Table 3-13, the use of intermediate cooling rather than high wet cooling can reduce cooling water requirements by 70.3-78.5 percent for power plants to 18.4-19.4 percent for Synthoil plants. While the water savings are the greatest for the power plant, the added cost (0.1

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[1] This assumes that the mine is sized to supply a 3,000 MWe power plant and that water is used for dust suppression and reclamation. See White, Irvin L., *et al*. *Energy From the West: Energy Resource Development Systems Report*. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

[2] Spent shale disposal is the largest consumer of water for above ground oil shale processing. Cooling water accounts for only 20 percent of the total.

TABLE 3-13: WATER USE REDUCTION FROM ALTERNATIVE COOLING[a]

TECHNOLOGY	SIZE	PERCENT OF TOTAL WATER REQUIRED FOR COOLING ASSUMING HIGH WET COOLING[a]	WATER USE REDUCTION USING INTERMEDIATE WET COOLING		WATER USE REDUCTION USING MINIMUM WET COOLING	
			PERCENT[b]	ACRE FEET PER YEAR	PERCENT[b]	ACRE FEET PER YEAR
Power Generation	3,000 MWe	82.7-92.3	70.3-78.5	18,390-20,340	NC	NC
Lurgi Gasification	250 MMscfd	45.1-70.4	22.5-35.2	1,490-1,670	29.0-45.3	1,920-2,140
Synthane Gasification	250 MMscfc	68.6-71.5	24.1-25.0	1,790-1,980	29.0-30.2	2,150-2,380
Synthoil Liquefaction	100,000 bbl/day	73.1-88.4	18.4-19.4	1,690-2,100	24.3-24.8	2,200-2,640

MWe = megawatt-electric
NC = not considered
MMscfd = million standard cubic feet per day
bbl/day = barrels per day

[a] Total water use and fraction used for cooling are based upon Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977. The range in values for these data is due principally to site specific differences. Modified in situ oil shale was not considered in this analysis. Power generation load factor is 70 percent; for synthetic fuels, 90 percent. This does not include water use in mining.

[b] The percent reduction is for cooling water requirements only and does not include total water requirements by the facility.

to 0.2 cents per kilowatt hour [kWh])[1] would be passed to the consumer.[2] The cost of intermediate cooling for coal synthetic fuels facilities (about one cent per million Btu's of energy produced) is a much smaller proportion of consumer costs. Variations in water savings for Lurgi gasification are due to variations in coal moisture content among sites; unlike other technologies, Lurgi uses the water in the coal directly.

(3) The Effect of Labor Intensity on Water Requirements

Table 3-14 gives estimates of the additional water required by the population increases associated with facility construction and operation. While this water demand averages an order of magnitude lower than demands for energy conversion facilities, it is not insignificant. Treatment and distribution systems will be required to supply water to meet increased demands. In the case of a technology such as gasification, where water requirements by the population during peak construction are 4.5 times that required during operation, overbuilding of treatment and distribution systems for the construction work force is a potential problem.

B. Water Effluents

Water effluents from energy facilities and population increases are discussed below.

(1) Effluents from Energy Facilities

Effluents removed as dissolved, wet and dry solids are listed in Table 3-15 for each technology. Effluents from surface retorting of oil shale are the largest, over 16 million tons per year (MMtpy), most of which is dry solids in the form of spent shale. Of the coal conversion facilities, Synthoil liquefaction produces the highest volume of total effluents and about twice as much as other synthetic processes. If valued on a Btu-electric basis, electric power generation produces more effluents per million Btu's produced than any other facility.

Dissolved and wet solid effluents will be diverted to evaporative holding ponds and later deposited in a landfill. Dry solids may be treated with water to prevent dusting and deposited in a landfill. As a result, water quality problems from effluent disposal do not arise from direct discharge to surface water but

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[1] Assuming water costs $0.25 per thousand gallons.

[2] This would increase costs to consumers from about 3 to 6 percent. Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977, p. 101.

TABLE 3-14: WATER REQUIREMENTS ASSOCIATED WITH POPULATION INCREASES[a]

TECHNOLOGY	WATER REQUIREMENTS (acre-feet per year)[b] PEAK CONSTRUCTION	OPERATION
Coal		
Surface Mine	71	323
Underground Mine	275	1,490
Gasification	1,570	350
Liquefaction	1,750	1,800
Power Plant	853	260
Oil Shale		
Surface Mine	119	194
Underground Mine	119	347
Retort and Processing	450	191
Modified In Situ	975	941

[a] Assumes 150 gallons per capita per day, a multiplier of 2 to account for added service personnel during construction, and a multiplier of 3.5 to account for families and service personnel during operation. Labor intensities are taken from Section 3.4.

[b] To convert acre-feet per year to gallons per day, multiply by 893.

indirectly from runoff to surface water and seepage to groundwater. Runoff from spent shale and water leaching through the shale represent major potential water quality problems, particularly if spent shale is dumped into ravines.[1] Total quantities are large, thus the potential for contamination is great. In no case is wastewater to be discharged directly into surface or groundwater systems; wastewater will be treated and recycled on-site.

The content of effluents from power plants and coal synthetic fuels facilities varies according to the elemental content of

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[1] Under the provisions of the Federal Water Pollution Control Act Amendments of 1972, Pub. L. 92-500, §§ 301, 402; 33 U.S.C.A. §§ 1311, 1342 (Supp. 1976), a permit may be required for this. Research is continuing into disposal methods for spent oil shale. Officials of TOSCO contend that after the addition of about 14 percent moisture and proper compaction the spent shale takes on cement-like qualities and leaching is negligible.

TABLE 3-15: SOLID EFFLUENTS FROM ENERGY CONVERSION TECHNOLOGIES[a]

TECHNOLOGY	SIZE	TOTAL EFFLUENTS[b]	
		(million short tons/year)	(pounds/10^6 Btu)
Coal			
Power Generation	3,000 MWe	0.526-2.554	
Per Btu electric			15.63-79.04
Per Btu thermal			5.48-26.60
Lurgi Gasification	250 MMscfd	0.448-1.680	10.91-40.91
Synthane Gasification	250 MMscfd	0.447-1.964	10.88-47.83
Synthoil Liquefaction	100,000 bbl/day	0.827-3.651	8.99-39.69
Mine (Power Plant)	12 MMtpy	0.00	0.00
Oil Shale			
TOSCO II Oil Shale	50,000 bbl/day	16.187	365
Underground Oil Shale Mine	26 MMtpy	0.00	0.00
Modified In Situ Oil Shale Processing	57,000 bbl/day	U	U
Modified In Situ Oil Shale Processing with Surface Retort	57,000 bbl/day	8.8	176
Oil			
Conventional Crude Oil Extraction	50,000 bbl/day	U	U
Enhanced Crude Oil Extraction	100,000 bbl/day	U	U
Gas			
Natural Gas Wells Production	250 MMscfd	0.00	0.00
Uranium			
Underground Mine	1,100 mtpd (ore)	N	N
Surface Mine	1,100 mtpd (ore)	N - 0.002	N - 0.01
Mill	1,000 mtpy (yellowcake)	0.367	2.45
Solutional Mine-Mill	250 tpy	0.003-0.004	0.08
Geothermal	100 MWe	U	U

Btu = British thermal units
MWe = megawatt-electric
MMscfd = million standard cubic feet per day
bbl/day = barrels per day
MMtpy = million tons per year
U = unknown
mtpd = metric tons per day
N = negligible
mtpy = metric tons per year
tpy = tons per year

[a] These data are from Radian Corporation. The Assessment of Residuals Disposal for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Austin, Tex.: Radian Corporation, 1978. This report extends and is based on earlier analyses conducted by Water Purification Associates and reported in Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977.

[b] Effluents include dissolved, wet, and dry solids. The range of values is that found at the six sites analyzed.

the source coal. Accumulations of wet-solids containing heavy metals, trace elements, and aromatic HC in holding ponds could produce acute effects in local surface waters, if they are released accidentally.[1] The quantities involved can be quite large. For example, at a typical site, such as Gillette, Wyoming, the operation of a power plant, Lurgi, Synthane and Synthoil synthetic fuel facilities would produce more than 68 million tons of solid effluents over a 25-year period.

In addition to possible berm failures which would allow pollution of surface waters, seepage from holding ponds can contaminate groundwater. The degree of contamination depends on the composition of materials in the ponds, holding pond design, liner design, pond management techniques, and the characteristics of nearby aquifers and of the soil overlaying the aquifer. In turn, contaminated aquifers may introduce pollutants into local springs, seeps, and streams. The quality of water in a polluted surface stream will usually improve dramatically within one to two years after pollution sources are eliminated; however, polluted aquifers require much longer periods to cleanse themselves, depending on local geologic and soil conditions.[2]

The disposal of effluents from scrubbing or ash removal is regulated under the Federal Water Pollution Control Act Amendments (FWPCA) of 1972,[3] and the Clean Water Act of 1977.[4] Groundwater quality is regulated under state laws in Colorado and New Mexico and, if it is used as a source of drinking water, under the Safe Drinking Water Act of 1974.[5] State solid waste disposal laws and regulations may also apply to on-site evaporative holding ponds. As noted earlier, the FWPCA may also apply to the disposal of spent shale.

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[1] Holding pond berm design must be site-specific, and failures are common in areas where previous design experience is not available. See Smith, E.S. "Tailings Disposal--Failures and Lessons," in Aplie, C.L., and G.O. Argall, eds. Tailing Disposal Today. San Francisco, Calif.: Miller Freeman, 1973, p. 358.

[2] Pettyjohn, Wayne A. Water Quality in a Stressed Environment. Minneapolis, Minn.: Burgess, 1972, p. 96.

[3] Federal Water Pollution Control Act Amendments of 1972, Pub. L. 92-500, §§ 301, 402; 33 U.S.C.A. §§ 1311, 1342 (Supp. 1976).

[4] Clean Water Act of 1977, Pub. L. 95-217, 91 Stat. 1566, 33 U.S.C. §§ 1251 *et seq*.

[5] Safe Drinking Water Act of 1974, Pub. L. 93-523, §§ 1424, 42 U.S.C.A. §§ 300h-3.

(2) Effluents From Population Increases

The population increases associated with energy development will impose increased demands on wastewater treatment facilities. Assuming that half of the water used must later be treated,[1] sewage treatment plants capable of treating 0.03-0.8 million gallons per day (depending on the technology) will be required to serve the additional population for each energy facility constructed. The total solids content of raw domestic sewage usually ranges from 500 to 1,000 milligrams per liter (mg/ℓ),[2] so that the wet-solids generated by population increases range from 0.06 to 3.3 tons per day (depending on the technology and solids content of the sewage). A portion of this is usually disposed of as sludge; it can either be buried in a landfill, used as a soil conditioner, or fermented to produce methane. These quantities are at least one thousand times less than the solids generated by energy facilities. As a result, the water quality problem associated with population increases is not one of the quantity of the wastes generated but of providing adequate treatment facilities.

Even in the quantities projected, untreated or poorly treated effluents can cause degradation of surface waters. Treatment facilities in many communities in the eight-state area are already unable to meet federal and state effluent standards. Since the need for sewage treatment is highest during the construction phase of conversion facilities, it may be impractical or infeasible for many communities to build sewage treatment plants to serve peak construction work forces that would be underutilized later.

C. Aquifer Disruption

Underground and surface coal, oil shale, and uranium mining can produce both surface and groundwater impacts. Underground and surface mines intercept groundwater aquifers, requiring mine dewatering operations that may deplete aquifers and, in some cases, create an excess water disposal problem.[3] In the area near Rifle, the oil shale being mined is an aquifer that supplies Piceance Creek. Mine dewatering can nearly eliminate the base flow of Piceance Creek (see Section 6.3).

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[1] In urban areas, the percentage of water use which must later be treated as sewage is 75-80 percent; we have assumed 50 percent since some of this population will be rural and served by septic tanks.

[2] McGauhey, P.H. Engineering Management of Water Quality. New York, N.Y.: McGraw-Hill, 1968.

[3] Sometimes the water obtained from dewatering operations can be used to supply water for mining, reclamation, and facility needs.

3.3.3 Variations in Existing Conditions

Existing conditions at individual sites and for the region as a whole will affect the type and degree of water impacts. The most important variables are the quantity, quality, and assessibility of water, the characteristics of the energy resource (particularly coal), aquifer characteristics, and climatic conditions. With the exception of water availability, the effect of these and several other less important variables on water impacts are identified in this section. Water availability issues are discussed at the regional level in Section 3.3.4.

A. The Quality of Available Water

Table 3-16 gives an indication of the water quality in rivers which will supply energy facilities. Only total dissolved solids (TDS) are included because this is the variable that most affects pretreatment for use by energy facilities or populations. Other water quality conditions can be important locally. For the six sites studied, the White River near Rifle has the lowest TDS (181 mg/ℓ), while Lake Powell near Kaiparowits has the highest (475-677 mg/ℓ). Portions of the Green River in the UCRB and of the Powder River in the UMRB have the highest levels of the surface waters studied as shown in Table 3-16.

Groundwater is often higher in dissolved solids than surface water but concentrations can vary considerably. Quality is generally better close to the sources of recharge. Because recharge sites are usually in the mountains, quality generally decreases as elevation decreases.

The EPA National Interim Primary Drinking Water Regulations do not specify a maximum level for dissolved solids. However, EPA has developed "water quality criteria" as one basis to inform state stream water quality programs and discharge permit applications. Criteria for domestic use recommend a TDS below 250 mg/ℓ. The U.S. Geological Survey Classification System calls water fresh if the dissolved solids content is less than 1,000 mg/ℓ; water is considered suitable for livestock if dissolved solids are less than 2,500 mg/ℓ.

B. Coal Characteristics and Climate

The coal characteristics at a site determine the quantity of wet solids in the effluent. In general, the coal characteristics have only a small effect on process water requirements

TABLE 3-16: TOTAL DISSOLVED SOLIDS IN SURFACE AND GROUNDWATER (milligrams per liter)

BASIN	SURFACE WATER	GROUNDWATER
Upper Colorado River Basin		1,000-40,000
Green River	307-1,688	
Upper Mainstem	207-621	
San Juan	159-447	
Upper Colorado River Region Outlet	558	
Upper Missouri River Basin		
Bighorn[a]	585	
Tongue[a]	380	
Powder[a]	1,425	
Yellowstone[a]	525	
Knife[a]	970	
Missouri Mainstem[a]	440	
Madison Aquifer		
Montana		500-1,000
North Dakota		3,000-10,000

[a] Measured in the Fort Union Coal Region.

except for the Lurgi process where coal moisture is important. Climatic conditions affect cooling water requirements and mine reclamation requirements and thus can affect total plant water consumption.

(1) Water Requirements

Table 3-17 summarizes water requirements by site. The data indicate that water requirements for conversion facilities in the Northern Great Plains (Beulah, Colstrip, and Gillette) are less than those in the Four Corners Area (Navajo/Farmington and Kaiparowits/Escalante). Facility water requirements at Beulah are the smallest, averaging 19 percent lower than those at Navajo/Farmington. A Lurgi gasification facility at Beulah will use 32 percent less water than at Farmington.

The moisture content of the coal is the principal cause of these site variations in the case of synthetic fuels. Lurgi makes direct use of the water derived from the coal, thus accounting for the large variations in this process's water use by site; for other synthetic fuel processes, the water in the coal is

TABLE 3-17: WATER REQUIREMENTS FOR EACH TECHNOLOGY BY SITE[a]

	WATER REQUIREMENTS[b] (1,000 acre-feet per year)				
SITE	ELECTRIC POWER GENERATION	LURGI	SYNTHANE	SYNTHOIL	Mine[c]
Kaiparowits/Escalante	29.82	NC	NC	NC	NC
Navajo/Farmington	29.21	7.13	8.67	11.75	3.11
Rifle	28.48	NC	NC	NC	NC
Gillette	25.84	5.82	7.78	9.23	0.41
Colstrip	26.66	6.28	7.81	10.30	1.29
Beulah	23.88	4.89	7.67	NC	3.15

NC = not considered

[a] Gold, Harris, *et al*. *Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States.* Washington, D.C.: U.S., Environmental Protection Agency, 1977. This assumes high wet cooling.

[b] For a 3,000 megawatt-electric power plant at 70 percent load factor, for 250 million cubic feet per day gasification facilities at 90 percent load factor, 100,000 barrels per day coal liquefaction facilities.

[c] Sized to supply a 3,000 megawatt-electric power plant.

assumed to be lost. The moisture content of coals at the six sites ranges from 13 percent at Rifle to 36 percent at Beulah.

Variations in the water requirements among sites for electric power generation result from differences in flue gas desulfurization water requirements (due to differences in the sulfur content of coal) and differences in the average temperature and humidity at each site; the hotter and more humid the air, the less cooling water it can absorb via evaporation.

Water requirements for mine irrigation depend on the climate, seam thickness of the coal, and Btu content of the coal.[1] Mine irrigation water requirements are high at Farmington (Table 3-17) because of the arid climate and at Beulah because of the low Btu content of the coal. They are low at Gillette primarily because of the thick seams characteristic of that area.

(2) Water Effluents

The ash and sulfur content of coal are largely responsible for site variations in quantities of effluent. At the six sites studied, coal ash content ranges from 5 percent at Rifle to 19 percent at Navajo/Farmington, and sulfur content ranges from 0.5 percent at Kaiparowits/Escalante to 1.0 percent at Colstrip. Coal with a high ash content will produce larger bottom or fly ash effluent streams, and coal with a high sulfur content will produce larger quantities of scrubber sludge effluent.

Table 3-18 indicates the variation by site in the quantity of solid effluent from four conversion technologies. Similar patterns are found for each technology; effluents can be more than four times higher at Kaiparowits/Escalante and Navajo/Farmington than at Gillette. The large quantity of effluent at Navajo/Farmington is associated with the high ash content of the coal (19 percent). Coal at Rifle has the lowest ash content (5 percent), and power generation there results in the smallest amount of solids, less than one-fifth of that at Navajo/Farmington.

C. Other Variables

Other factors that vary by site and affect water impacts are the water requirements of reclamation and the soil and aquifer characteristics at a site. Water requirements for reclamation depend largely on climate and coal seam thickness. These requirements are expected to be higher in the arid Southwest where average rainfall is lowest, particularly during the summer growing season, and where coal seams are generally thinner (10.3 feet at Kaiparowits/Escalante).

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[1] The lower the Btu content of the coal the larger the amount of land disturbed and needing revegetation, all other factors being equal, to supply a given amount of energy.

TABLE 3-18: TOTAL SOLIDS RESIDUALS FOR EACH TECHNOLOGY BY SITE[a]

SITE	TOTAL SOLIDS[b] (million short tons per year)			
	ELECTRIC POWER GENERATION	LURGI	SYNTHANE	SYNTHOIL
Kaiparowits/Escalante	2.7	NC	NC	NC
Navajo/Farmington	2.6	1.7	2.0	3.7
Rifle	0.5	NC	NC	NC
Gillette	0.6	0.4	0.4	0.8
Colstrip	1.1	0.8	0.7	1.4
Beulah	1.1	0.7	0.7	1.1

NC = not considered

[a] Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977. These estimates do not include the water in the effluents.

[b] For a 3,000 megawatt-electric power plant at 70 percent load factor, for 250 million cubic feet per day gasification facilities at 90 percent load factor, and 100,000 barrels per day coal liquefaction facilities at 90 percent load factor.

Soil and aquifer characteristics are important to the fate of effluents. Those characteristics vary widely both regionally and locally; thus, they are particularly important when locating a disposal pond. Low soil permeability (as in clay) is desirable to prevent seepage of effluents. More permeable, loamy soils are desirable in septic tank drain fields to provide higher capacity and better filtration of sewage effluents.

3.3.4 Regional Impacts

Water impacts in the region are dependent on the existing quantity and quality of the supply and on the kind and level of energy development. Estimates of the amount of water available and future requirements are discussed for the UCRB and the UMRB. Projected wastewater and solid waste generation are given, followed by a general discussion of impacts.

A. Water Supply Availability and Demand

Surface water availability estimates and the requirements for the hypothesized energy development (in the year 2000) are given in Table 3-19. The allocation of water rights and the legal/political problems surrounding them will be important in determining whether a portion of the unused water (about 1.5 to 3 million acre-ft/yr in the UCRB) can be used for energy development.

As indicated in Table 3-19, by 2000 water requirements for the energy conversion facilities, assuming wet cooling, and associated population increase in the UCRB are predicted to be 311.5-1348.8 thousand acre-ft/yr, for the Low Demand and Nominal Demand cases, respectively. Use of intermediate wet cooling instead of high wet, at all facilities would reduce this regional water demand by 19 percent in the Low Demand case, or about 60 thousand acre-ft/yr. Population related water requirements are about 10 percent of those for the energy facilities. Water demand will also come from mining operations.

Large quantities of groundwater exist in the UCRB. They are more evenly distributed than surface water and generally have a higher TDS content. The most important aquifers in the UCRB are in alluvial deposite along rivers and streams. These aquifers are recharged at a rate of 4 million acre-ft/yr (twice the water available from surface streams) and store a total of 115 million acre-ft at a depth of less than 100 feet.[1] Greater quantities occur in deeper reservoirs.

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[1] Price, Don, and Ted Arnow. Summary Appraisals of the Nation's Ground-Water Resources--Upper Colorado Region, U.S. Geological Survey Professional Paper 813-C. Washington, D.C.: Government Printing Office, 1974.

TABLE 3-19: SURFACE WATER DEMAND AND AVAILABILITY, YEAR 2000
(thousand acre-feet per year)

WATER USE	UPPER COLORADO RIVER BASIN	UPPER MISSOURI RIVER BASIN
Regional Scenario[a] assuming high wet cooling[b]		
Energy Facilities	287.0 - 1,265.0	882.0 - 1,216.6
Population	24.5 - 83.8	86.7 - 125.9
Total:	311.5 - 1,348.8	969.6 - 1,342.5
Regional Scenario[a] assuming intermediate wet cooling[c]		
Energy Facilities	227.0 - 1,169.0	507.1 - 752.9
Population	24.5 - 83.8	86.7 - 125.9
Total:	251.5 - 1,252.8	593.8 - 878.8
Water available (1975)	1,550.0 - 3,100.0[d]	12,500[e]

[a] The range in values represents the Low Demand and Nominal Demand cases.

[b] White, Irvin L., et al. Energy From the West: Energy Resource Development Systems Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

[c] Gold, Harris, et al. Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States. Washington, D.C.: U.S., Environmental Protection Agency, 1977.

[d] The range reflects a difference in estimates of surface water availability in the Upper Colorado River Basin of 5.25 - 6.3 million acre-feet per year minus 1974 depletions of 3.2 - 3.7 million acre-feet per year. See Chapter 11 for elaboration of these estimates.

[e] Based on the estimate of 19 million acre-feet per year practical limit for water depletions minus 6.5 million acre-feet per year average depletion. See Chapter 11 for a discussion of these estimates.

In the UMRB, water availability does not appear to be a problem as a whole; the water not already allocated is well in excess of anticipated requirements (Table 3-19). However, water supplies may be inadequate in parts of the UMRB. A great deal of uncertainty exists with regard to water rights in the UMRB. These uncertainties appear likely to be less significant than in the UCRB because a greater excess flow is available. However, allocations in the Yellowstone River Basin are currently under review, and the Montana Fish and Game Department and State Health Department have applied for instream flow allocations of 6.6 and 8.2 million acre-ft, respectively. If granted, these uses would curtail major diversions in Montana for either energy or agricultural use. Agricultural demands, particularly for irrigation, are also expected to increase in the future.

Projected water use by the energy facilities in the year 2000, if high wet cooling is employed, is 882 thousand acre-ft/yr for the Low Demand scenario and 1216.6 thousand acre-ft/yr for the Nominal (or 7-10 percent of the total available). A reduction in water demand of about 40 percent may be realized if intermediate wet cooling is used in the Low Demand case. Potential reduction in water demand by wet/dry cooling is higher in the UMRB because oil shale facilities are located in the UCRB and the water requirements for oil shale technology can not be reduced substantially by the use of intermediate wet cooling.

There are numerous aquifers in the UMRB. A total of 860 million acre-ft is estimated to be stored in the upper 1,000 feet of rock in the basin.[1] However, withdrawal rates are often constrained by low permeability.

B. Effluents

Table 3-20 shows total solids and wastewater estimated to be generated by the energy facilities and related population increases in the year 2000. The range of values represents differences between the Low and Nominal Demand cases.

In general, population-related production of solids (almost entirely as sewage sludge) is negligible compared to those produced by the energy facilities. The quantity of wastewater generated by the population, however, is not negligible, being about 50-90 percent as large as that generated by the energy facilities.

In the UCRB, oil shale development (both TOSCO II and modified *in situ*) contributes 85 percent in the Low Demand case and

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[1] Missouri Basin Inter-Agency Committee. *The Missouri River Basin Comprehensive Framework Study*, 7 vols. Denver, Colo.: U.S., Department of the Interior, Bureau of Land Management, 1971.

TABLE 3-20: PROJECTED REGIONAL SOLID RESIDUALS AND WASTEWATER: YEAR 2000[a]

SOURCE	UPPER COLORADO RIVER BASIN		UPPER MISSOURI RIVER BASIN	
	SOLIDS (MMtpy)	WASTEWATER (thousand acre-ft/yr)	SOLIDS (MMtpy)	WASTEWATER (thousand acre-ft/yr)
Energy facilities	130.87 - 552.75	30.35 - 64.49	39.02 - 56.8	61.26 - 87.63
Population[b]	0.01 - 0.04	16.33 - 55.85	0.04 - 0.06	57.80 - 83.91
Total	130.88 - 552.79	46.68 - 120.34	39.06 - 56.91	119.06 - 171.54

MMtpy = million tons per year   acre-ft/yr = acre-feet per year

[a] The range in values represents the Low Demand and Nominal Demand cases.

[b] Wastewater at 100 gallons/person/day and 500 milligrams per liter solids; population increases from Chapter 11.

95 percent in the Nominal case of the total solids produced by energy development in the Basin. This is due primarily to the spent shale generated. Overall solid effluents in the Nominal case are more than four times those in the Low Demand case, and wastewater is more than two times greater in the Nominal Demand case. In the UCRB, 37-58 percent of the total wastewater from energy facilities is from the uranium mills.

In the UMRB, solid effluents generated by the energy facilities are estimated to range from 39.06 to 56.91 MMtpy. The quantity of wastewater produced ranges from 119.06 to 171.54 thousand acre-ft/yr, 80 percent of which is attributed to power plants and gasification facilities.

3.3.5 Summary of Technological and Locational Factors

Some technology-related problems, in combination with certain site characteristics, cause water impacts to be particularly severe. These severe impacts can often be mitigated by choosing a different technology for the problem site, a different site for the problem technology, or an entirely different technology-site combination. Table 3-21 lists the problems that can arise because of technology-site combinations and indicates the technology- and site-related factors which cause the problems.

Water for energy conversion facilities is less clearly available in the UCRB than in the UMRB. Water for energy development in New Mexico is particularly limited. Since electric power generation requires more water than any other conversion technology, a worst-case combination in terms of water impacts is to site an electric power plant in New Mexico. Further, the generally low moisture content of southwestern coals and the hot climate means that energy conversion will require more water in that area.

Groundwater availability for energy conversion is highly uncertain in both the UCRB and UMRB. There is undoubtedly more groundwater in the UMRB than in the UCRB, but the amounts in the Upper Colorado cannot be ignored as a source for energy development. Mitigation of water use shortages and conflicts may require the use of wet/dry cooling (particularly in the Southwest) or the export of coal from the UCRB.

If groundwater contamination through seepage from evaporative holding ponds (which retain the liquid wastes from power generation and coal-synthetic fuels) is to be prevented, careful siting and construction of these ponds will be required. Prevention of groundwater contamination via seepage through spent shale remains an unsolved problem since spent shale will not be held in

TABLE 3-21: SUMMARY OF WATER PROBLEMS

WATER PROBLEMS	COMBINATIONS OF FACTORS THAT CAUSE THE PROBLEM	
	TECHNOLOGICAL FACTORS	LOCATIONAL FACTORS
Severe water shortages generating water rights conflicts	Water requirements of conversion facilities (especially electric power generation) and related population increases	Scarce water resources, particularly in Upper Colorado River Basin (especially New Mexico), moisture content of the coal, climate
Groundwater contamination from facility effluent	Effluents from conversion facilities (especially oil shale processing)	Soil permeability and aquifer depth
Surface water contamination from domestic sewage	Electric power generation, coal gasification	Small communities or others with treatment facilities operating near capacity
Aquifer disruption	Mining	Location of the aquifer relative to the seam

lined ponds.[1] In the vicinity of evaporative holding ponds and spent shale disposal sites, soil permeability should be low and aquifers at great depth. The longer any seepage remains in the soil prior to migrating to an aquifer, the more contaminants that can be absorbed by the soil. Given the uncertainties surrounding the probable increase in seepage rates over time, migration calls for strict design standards for evaporative holding ponds and new approaches to spent shale disposal.

Surface water contamination from untreated or poorly treated domestic sewage is a potential problem wherever and whenever population increases outstrip the capacity of sewage treatment plants. The problem can be critical when construction work forces are larger than operating work forces, as in the case for an electric power plant and coal gasification plant. Small communities, where the capacity of sewage treatment facilities is limited and effluent quality is marginal, are particularly susceptible to sewage overloads. Mitigation calls for policies that require sewage treatment expansion prior to the construction of a conversion facility or for temporary sewage treatment arrangements during the construction phase.

Aquifer disruption, with concomitant reduction in groundwater flow to surface streams, is a potential problem wherever mining takes places within an aquifer. Although aquifer characteristics cannot be fully restored, mitigation may require reclamation of the mined areas as mining proceeds rather than reclamation after the life of the mine. This may reestablish groundwater flow and keep to a minimum the length of time flow is disrupted.

3.4 SOCIAL AND ECONOMIC

HIGHLIGHTS

- **CRITICAL FACTORS**
  - *Three technological factors can significantly affect the social and economic impacts of energy development: labor intensity; capital intensity; and scheduling.*
  - *Six locational factors can also significantly affect these impacts: community size and location; capabilities of existing institutions; historical out-migration; characteristics of the local labor force; local financial conditions; and the culture and lifestyles of an area.*

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[1] As noted earlier, TOSCO officials contend that moisturizing and properly compacting spent shale causes a cementation that greatly reduces leaching problems.

- **LABOR INTENSITY**
  - The requirements for housing, schools, and other public and private facilities and services are largely determined by the labor intensity of the energy technologies deployed.
  - On an equivalent energy basis, labor requirements for coal gasification are greater than for the other conversion technologies considered; TOSCO II oil shale retorting and electric power generation require the least (on a per-Btu thermal basis).
  - Large differences between construction and operating labor requirements exacerbate population-related impacts. In such cases, services and facilities will be inadequate during the construction phase or overbuilt for the operations phase.
  - Among conversion technologies, coal gasification has the largest difference between construction and operation phase labor requirements; coal liquefaction has the smallest.
- **SCHEDULING**
  - Simultaneous scheduling of labor intensive technologies in an area will exacerbate social and economic impacts by concentrating the number of workers and exaggerating differences in construction and operating phase labor requirements.
  - Prolonging construction schedules can minimize impacts. For gasification facilities, extending construction schedules from five to eight years can reduce peak labor requirements by one-third.
-
  - All conversion technologies are more capital intensive than mines and can produce public revenues in excess of added public expenditure requirements over the long term.
  - Property taxes are generally not available during construction when demands on local governments are generally greatest.
- **JURISDICTIONAL DISTRIBUTION**
  - Increases in revenues will often go to county governments, but towns will have to absorb most of the population increases and meet most of the facilities and services needs.
- **COMMUNITY CHARACTERISTICS**
  - Rural areas and small communities will experience more dramatic "boom" type impacts and require longer lead times to provide adequate services and facilities.

- *Isolated communities are more likely to experience severe "boom" type impacts than will any one community in an area where there are numerous towns in the vicinity of an energy development.*
- *Population impacts will be less in communities where the local labor force can meet some of the labor needs of energy development.*

3.4.1 Introduction

Most of the social and economic impacts expected to occur as a consequence of western energy development stem directly from large and rapid population increases. The magnitude of the population increase that can be expected is related to the labor force required by the energy technologies being used and the size of the development. The magnitude and seriousness of the resulting social and economic impacts are related to the conditions existing in the area at the time the development takes place.

3.4.2 Variations Among Technologies

Features of energy technologies that can have significant impacts on social and economic conditions are labor requirements, scheduling, and capital intensity. These features help determine the pace and extent of migration to an area, as well as the financial and managerial capability of local governments to provide services and capital facilities.

A. Labor Requirements

Labor-intensive energy resource developments will attract a large number of people to jobs in development areas and magnify social and economic impacts. An annual population growth rate of more than seven percent, for example, will double population in less than 10 years and tend to produce serious dislocating impacts on small towns and rural areas.[1]

Further, labor forces will vary during the construction phase and between the construction and operation phases of an energy facility. One overall labor indicator that facilitates a comparison of technologies is the ratio of peak construction personnel to operational personnel requirements (Table 3-22). A high ratio indicates that more workers are needed during construction than during operation. This results in excess requirements for housing, schools, and other public and private services during the construction phase, and increases the likelihood that services and facilities will be inadequate and that quality of life will decline. Coal gasification, electric power generation, geothermal facilities, and oil shale retorting have the highest ratios, indicating that demands on local communities will be large during construction and much smaller during operation. Conversely, coal, uranium, and oil shale mining will have a larger population after construction is finished.

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[1] See, for example, Ford, Andrew. Summary Description of the BOOM1 Model. Los Alamos, N. Mex.: Los Alamos Scientific Laboratory, 1976; and University of Denver, Research Institute. The Social, Economic and Land Use Impacts of a Fort Union Coal Processing Complex, Final Report, for the U.S. Energy Research and Development Administration. Springfield, Va.: National Technical Information Service, 1975.

Obviously, if an energy resource development requires a substantially greater labor force during construction, a local building program designed to meet construction population needs will result in an excess of permanent facilities over the long term. Likewise, when the construction phase of a development lasts for several years, facilities designed primarily for the population size expected over the long term may result in inadequate facilities for most of the construction period. In such a case, some problems can be alleviated rather easily, but others cannot. For example, schools can schedule double sessions and/or erect temporary facilities to accommodate additional pupils, but medical facilities may become overloaded and attracting additional medical personnel to the area may be difficult. Most doctors would probably be unwilling to establish practices in these areas, knowing that they might be forced to relocate within a few years. Similarly, local landlords and investors would not be likely to build adequate housing for the short-term population, knowing that the demand for housing should drop markedly within a few years.

A second indicator of labor intensity is the sum of peak construction and operation manpower requirements (Table 3-23). This indicator suggests that coal liquefaction, crude oil production, and coal gasification are the most labor-intensive technologies for the energy outputs of the facilities assumed in our scenarios. However, this ordering changes somewhat when a uniform energy output of 10^{15} Btu's per year is assumed; under this assumption, coal gasification, crude oil production, and geothermal require the most labor. The labor intensity of electric power generation depends on how the energy produced is measured. If measured as electricity output, its labor intensity is similar to that for coal synthetic fuels; if measured as thermal input, its labor intensity is similar to that of an underground coal mine. By both measures, uranium mining and milling and surface coal mining are low in overall manpower requirements.

Larger work forces contribute both directly and indirectly to population increases in communities near energy development

TABLE 3-22: CONSTRUCTION AND OPERATIONAL MANPOWER REQUIREMENTS FOR ENERGY FACILITIES

FACILITY	MANPOWER REQUIREMENTS[a]			
	CONSTRUCTION			
	DURATION (YEARS)	PEAK EMPLOYMENT	OPERATION	RATIO[b]
Coal				
Surface Mine	5	210	550	0.4
Underground Mine	7	820	3,000	0.3
Gasification	5	4,680	590	7.9
Liquefaction	7	5,000[c]	2,930[c]	1.7
Power Plant	8	2,540	440	5.8
Oil Shale				
Underground Oil Shale Mine	4	360	590	0.6
Modified *in situ* Oil Shale Processing[d]	6	1,950	510	3.8
Modified *in situ* Oil Shale Processing with Surface Retort[d]	U	U	U	U
TOSCO II Oil Shale Processing	6	1,340	330	4.1
Oil				
Conventional Crude Oil Production[e]	7	3,920	2,050	1.9
Enhanced Crude Oil Production[e]	U	U	U	U
Gas				
Natural Gas Production[e]	4	1,700	790	2.1
Uranium				
Surface Mine (open pit)	5	80	180	0.4
Underground Mine	8	80	930	0.1
Solutional Mine	2	50	60	0.8
Mill	3	90	110	0.8
Geothermal		290	28	10.3

U = unknown

[a] The listed requirements are for the typical size facilities shown in Table 3-7. Data are from Carasso, M., et al. The Energy Supply Planning Model. San Francisco, Calif.: Bechtel Corporation, 1975, vol. 1, pp. 6-30 to 6-31, and involve uncertainties of -10 to +20 percent; data for developing technologies (coal liquefaction, gasification, and oil shale processing) involve uncertainties of -30 to +75.

[b] The ratio expressed is Construction/Operation. The larger the ratio, the greater the employment decline when construction ends.

[c] Carasso et al. Energy Supply Model. pp. 6-7 to 6-15. This figure is among those with the greatest uncertainty. In addition, economies of scale are not incorporated into coal liquefaction facilities over the 21,700 barrels per day plant assumed by Bechtel. Recent pilot plant studies have indicated that approximately half the number of operation personnel will be required.

[d] White, Irvin L., et al. Energy From the West: Energy Resource Development Systems Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming, Chapter 4.

[e] Includes exploration (including dry holes), development, and production. See Carasso et al. Energy Supply Model, pp. 6-7 to 6-15.

TABLE 3-23: MANPOWER REQUIREMENTS FOR ENERGY FACILITIES

FACILITY	ASSUMED FACILITY SIZE	MANPOWER REQUIREMENTS[a]	
		FOR ASSUMED FACILITY	FOR PRODUCTION OF 10^{15} Btu/year[b]
Coal			
Surface Mine	12 MMtpy	760	3,960
Underground Mine	12.7 MMtpy	3,820	19,900
Gasification	250 MMcfd	5,270	64,170
Liquefaction	100,000 bbl/day	7,930	43,100[c]
Power Plant	3,000 MWe	2,980	
Btu electric			44,280
Btu thermal			15,520
Oil Shale			
Underground Oil Shale Mine	26 MMtpy	950	5,690
Modified *in situ* Oil Shale Processing	57,000 bbl/day	2,460	24,330
Modified *in situ* Oil Shale Processing With Surface Retort	57,000 bbl/day	U	U
TOSCO II Oil Shale Processing	50,000 bbl/day	1,670	18,830
Oil			
Conventional Crude Oil Production	50,000 bbl/day	5,970	64,910
Enhanced Crude Oil Production	100,000 bbl/day	U	U
Gas			
Natural Gas Production	250 MMcfd	2,490	30,320
Uranium[d]			
Surface Mine (open pit)	1,100 mtpd (ore)	260	870
Underground Mine	1,100 mtpd (ore)	1,010	3,370
Solutional Mine-Mill	250 tpy (yellowcake)	110	1,470
Mill	1,000 mtpy (yellowcake)	230-310	772-1,040
Geothermal	100 MWe	320	
Btu electric			141,760
Btu thermal			49,690

Btu/year = British thermal unit per year
MMtpy = million tons per year
MMcfd = million cubic feet per day
bbl/day = barrel per day
MWe = megawatt-electric

U = unknown
mtpd = metric tons per day
tpy = tons per year
mtpy = metric tons per year

Source: Carasso, M., *et al*. *The Energy Supply Planning Model*, 2 vols. San Francisco, Calif.: Bechtel Corporation, 1975.

[a] Includes both peak construction and operation employment requirements (see Table 3-22).

[b] 10^{15} Btu's per year in the product.

[c] Recent pilot plant studies have indicated approximately half the operating personnel will be required.

[d] Assumes ore contains approximately 0.2 percent yellowcake.

sites. Larger populations mean larger demands for housing, public facilities, and public and private services, as well as greater stress on roads and streets and law enforcement agencies. Thus, any large and rapid increase in population creates a substantial demand for additional services and facilities from local governments.

B. Scheduling

The construction schedule for the energy facilities within a local area is an important technological factor which influences the extent of local population impacts. When several facilities are constructed at the same time small, rural communities will probably be unable to accommodate the population growth.[1] For example, simultaneous scheduling of technologies that are labor intensive in their construction phase will cause the workers for two or more projects to be located in the same area at the same time. Currently, no means exist to coordinate the scheduling of several energy developments in an area, and such a goal might only be met by limiting the rate of development of western resources. Institutional inadequacies impede joint public and private sector planning. At the least, industry and local government often fail to communicate with each other in advance of development. Also, both are affected by federal policy and associated uncertainties.

Conversely, if construction is prolonged, so is the period of population instability. It may be easier for communities to deal with temporary construction-related impacts if the period of instability is minimized.[2] If construction of successive projects involves large gaps of time with no construction, communities may become dependent on construction projects to reduce unemployment and add to local economic stability. Thus, service shortages may take place each time construction occurs and unemployment when it does not.

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[1] Walton, Barry L. "Population Growth Constrained Synthetic Liquid Fuel Implementation Scenarios," Chapter 22 in Dickson, Edward M., et al. Impacts of Synthetic Liquid Fuel Development: Automotive Market, Vol. III. Menlo Park, Calif.: Stanford Research Institute, 1976.

[2] Planning for stability would require adequate information from all energy developers in the area as well as an adequate professional planning capability. See White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

C. Capital Intensity

A community benefits economically from energy development primarily through increases in its tax base and revenues beyond the expenditures needed to meet expanded facilities and services requirements, and increases in personal incomes. Given the tax structure in most communities, an expanded property tax base and increased revenues are the most important sources of benefit; the extent of the community's benefit from both depends on the capital intensity of energy facilities. Large conversion facilities, in particular, are contributors to local revenues and can produce substantial excess revenues in the long term.

In the short term, however, even capital-intensive facilities cause problems because property taxes generally are not available during construction when the demands on local governments are often greatest. Further, there is a jurisdictional division between municipalities experiencing most of the population impact and service demands and the counties and school districts receiving the taxation benefits. This is discussed further in Section 3.4.3.

Local merchants and local residents employed by energy developers tend to gain most economically during the construction phase. However, the majority of construction workers usually come from outside the local area.[1] This, of course, reduces the benefits that residents often anticipate before construction begins. During operation, a relatively large number of workers tend to be local residents, and new opportunities open up in local service industries.

3.4.3 Variations in Existing Conditions

The conditions that exist at an energy development site play a large part in determining the actual type and degree of social and economic impacts. For example, impacts will vary depending upon such factors as community size and location, capabilities of existing institutions, historical out-migration, characteristics of the local labor force, local financial conditions, and the culture and lifestyle of an area.

A. Community Size and Location

The most important existing condition that influences the extent of population impact is the size of a community before energy development begins. Larger cities have more diversity and capacity for growth in both the public and private sectors. Our research suggests that communities of less than 2,000 population will almost always have inadequate services and planning capabilities.[1] Communities of up to 5,000 also may fall into this category. Conversely, cities of 10,000 or more (especially those greater than 25,000) usually have a developed community service system and planning professionals.[2] Thus, in most larger communities, lead-time problems are reduced because they generally have plans for expansion, although acquiring funds for expansion may be a problem regardless of city size.

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[1] For documentation of this, see Mountain West Research. Construction Worker Profile, Final Report. Washington, D.C.: Old West Regional Commission, 1976.

In addition to size, the number of communities in the vicinity of an energy development will affect the relative impacts on each town. An isolated town that is the only possible place for workers and their families to live will receive much greater impacts than one town in an area where the new population is more widely distributed.[3] Construction of a new town is a partial solution to the inability of any single community to absorb new population. A similar solution is for an energy developer to provide housing and community services by expanding an existing village or town.[4] However, developers do not always do so, leaving the cost of streets, water, sewer, and other services to very small, unincorporated towns. In many cases, state and county laws and regulations are not adequate to control growth in these settlements. Large cities of 25,000 population or more can more easily absorb population growth, simply because the growth represents a smaller proportion of their initial size.

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[1] Planning and growth management capabilities consist primarily of a full-time staff of professional planners, good knowledge of existing facilities in the town, and a plan of future developments in anticipation of growth.

[2] For documentation of recent energy-related growth in western towns of all sizes, see U.S., Federal Energy Administration, Region VIII, Socioeconomic Program Data Collection Office. Regional Profile: Energy Impacted Communities. Lakewood, Colo.: Federal Energy Administration, Region VIII, 1977.

[3] For example, Gillette's isolation in northeastern Wyoming has resulted in greater impacts for Gillette than have occurred in Rifle, Rangely, Meeker, and Grand Valley in western Colorado, where several towns share the impacts. See Chapters 6 (Rifle) and 7 (Gillette).

[4] For information on the activities of energy developers in this area, see Metz, William C. "Residential Aspects of Coal Development." Paper presented at the Meeting of the American Institute of Planners, Kansas City, Missouri, October 1977; and White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

Although the private sector often is slow in responding to increased demands for goods and services in rapid-growth situations, the reaction of local governments has tended to be even slower, especially in smaller towns.[1] Availability of funds is a major cause of this lag for all communities, but the time span is usually greater in small communities because of their lack of planning capabilities. Moreover, outside entities, rather than local businesses, are more likely to meet private service needs in smaller communities, with the result that much of the economic benefit can flow out of the local area.

B. Capabilities of Existing Institutions

As the site-specific analyses in Chapters 4-9 indicate, growth leads to demands for housing and essential public facilities and services, for professional services, and ultimately for social and cultural opportunities. Many western rural communities are not accustomed to providing such a full range of services and, in any case, are severely strained by the rate at which these demands escalate. Moreover, the manageability of these problems is often reduced by inadequate tax bases and planning capabilities.[2]

Besides governmental service problems related to growth, most small communities affected by energy development will more than double in size, resulting in newcomers outnumbering natives (including former residents who return because of the employment opportunities energy developments offer). Not only will community leadership probably shift from the small businessmen and ranchers who presently lead these communities, but the dominant attitudes and values of the townspeople will probably change. Thus, the new majorities and leaders may force communities to make changes and undertake programs that current residents presently oppose. For example, many of these communities have an antipathy to planning and are reluctant to seek or accept assistance from other levels of government.[3] Yet, regardless of leadership or values, most of these communities must develop a planning capability and accept intervention and assistance from state and federal governments. In fact, these communities may even play a leading role in bringing pressure to bear on state and federal governments to provide assistance.[1]

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[1] Breese, Gerald, et al. The Impact of Large Installations on Nearby Areas: Accelerated Urban Growth. Beverly Hills, Calif.: Sage, 1965, p. 589.

[2] See the discussion of community facilities and services in White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming, Chapter 9.

[3] See Christiansen, Bill, and Theodore H. Clack. "A Western Perspective on Energy: A Plea for Rational Energy Planning." Science, Vol. 194 (November 5, 1976), pp. 578-84.

Increased strain in intergovernmental relations is another impact of rapid population growth. The sources of strain can be found in almost every problem area that has been discussed in this chapter, but particularly in the problems of: the benefits of public revenue increases accruing to jurisdictions other than the ones which must provide expanded municipal services; the pressure on the states and the federal government to provide assistance to impacted areas; and uncoordinated regulatory and policy roles assumed by various levels of government.

C. Historical Out-Migration

Some areas, particularly in the Northern Great Plains, have seen their populations decline gradually for several decades.[2] In some ways, historical out-migration puts those areas in a better position to accommodate rapid energy development. First, excess capacity in adequately maintained community facilities, such as schools and water supply, could allow time before new facilities must be constructed. This is a luxury not available in most parts of the West, where medium-size cities have experienced recent growth and generally have no excess capacity.[3]

Another advantage of recent out-migration is that many of the people who had moved away may want to return to work in energy development. This could reunite many families and, from a community point of view, less social readjustment will be necessary than with a work force completely unfamiliar to the area.

D. Local Labor Force

Another existing condition that influences the extent of population impact is the size and composition of the local labor force. If local unemployed and underemployed persons are afforded the opportunity of training programs, the number of nonlocal workers required might be significantly lowered. This is more easily accomplished for operation than for construction trades, which often require years of specialized experience. Of all construction occupations, those most likely to be filled by local residents are laborers, cement finishers, and carpenters, but even those occupations have involved 40 to 50 percent nonlocal workers. The proportion is up to 80 percent for some skills.[1]

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[1] U.S., Congress, Senate, Committee on Environment and Public Works. Inland Energy Development Impact Assistance Act of 1977. Hearings before the Subcommittee on Regional and Community Development, 95th Cong., 1st sess., August 2 and 27, 1977.

[2] For example, North Dakota has faced net declines in three of the last four decades.

[3] U.S., Federal Energy Administration, Region VIII, Socioeconomic Program Data Collection Office. Regional Profile: Energy Impacted Communities. Lakewood, Colo.: Federal Energy Administration, Region VIII, 1977.

Energy employment represents an opportunity for Indian nations to share in industrial development if they wish it, although the lack of training among Indians is a barrier to employment. However, many Navajo workers have acquired training, especially in coal mining operations, and have joined labor unions, at least in part because of the higher earnings associated with union jobs.[2]

Unless lease terms or training programs are focused on local residents, the largest category of new employment for local residents tends to be in relatively low-paying service jobs, perhaps in new businesses established by local entrepreneurs.[3] Professional and other more specialized service jobs (such as in medicine and education) induced by population growth also commonly go to outsiders. Larger communities will experience more job switching to new employment opportunities, but even in these towns specialized skills are unlikely to be available in great numbers.

E. Local Financial Conditions

Two major site-specific variables are the legal and financial capacities of local governments to respond in a timely manner. Some state governments have passed legislation enabling communities to act decisively on their own and have established programs to provide funding assistance from taxation on energy resources specifically aimed at impacted communities.

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[1] Mountain West Research. Construction Worker Profile, Final Report. Washington, D.C.: Old West Regional Commission, 1976.

[2] The United Mine Workers operate the Black Mesa Mines, and the Operating Engineers man the Utah International Mine at Four Corners. Locals of both unions have approximately 70 percent Navajo membership. Robbins, Lynn A. Navajo Participation in Labor Unions, Lake Powell Research Project Bulletin No. 15. Los Angeles, Calif.: University of California, Institute of Geophysics and Planetary Physics, 1975.

[3] Gray, Irwin. "Employment Effect of a New Industry in a Rural Area." Monthly Labor Review, Vol. 92 (June 1969), pp. 26-30; Summers, Gene F., et al. Industrial Invasion of Nonmetropolitan America. New York, N.Y.: Praeger, 1976.

The adequacy of new revenue for impacted communities will depend primarily on timing and distribution; that is, funds for the expansion of community facilities and services will not always be available at the proper times or in the most appropriate jurisdictions. Four of the states in the study area (Montana, North Dakota, Utah, and Wyoming) have taken special actions to deal with the initial capital requirements of cities and counties. Their programs are described in the impact analyses reported in Chapters 4-9. Briefly, these programs provide impacted communities "front-end" money with which to meet facility and service requirements. Utah permits the prepayment of taxes for state-related public improvements; and Montana, North Dakota, and Wyoming have statutory formulas for earmarking a portion of revenues from mineral leasing and severance taxes for payment directly to the impacted communities. The effectiveness of these programs depends on distribution formulas and policies, as discussed in Chapter 9 of our Policy Analysis Report.[1]

However, state programs resolve only part of the timing problem associated with getting funds to local governments and do even less to resolve completely the larger distribution problem. For example, county governments, the principal recipient of ad valorem property taxes, are often major beneficiaries of new revenues produced by energy development but, as noted earlier, cities and towns normally must provide most of the services and facilities. In Utah, Wyoming, and Colorado, special districts for water, sewers, schools, fire protection, and other purposes can bridge the city/county jurisdictional boundary and insure that new revenues are used at the impacted locations.

Based on the results of the regional impact analysis reported in Section 11.4.4, long-term energy-related revenues at the state and local levels will exceed in the aggregate the new revenues required to serve the expanded populations. However, the types of legislation discussed here (and conscientious administration of the programs by the designated state boards) will be necessary to insure that the revenues are used when and where they are needed. The present programs in some western states have the opposite effect and, in fact, cause a lag between the time when impacts are experienced and when revenues are available.

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[1] White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming.

F. Quality-of-Life, Lifestyle, and Culture

"Quality-of-life" is largely a subjective attribute composed of a variety of factors. Usually though the availability of medical care, professional services in general, and adequate housing play an important role in residents' opinions on the quality of their lives. When public and private services are unavailable, the local quality-of-life is generally considered to be low.[1]

The capability to plan adequately for local population impacts will largely determine the quality-of-life impacts in the West. Service infrastructure, such as utilities and streets, are common concerns for local residents. In the private sector, housing shortages handled by mobile homes are not very satisfactory either to those living in them or to others in the community. For a variety of reasons, doctors tend not to locate in small, isolated towns, making medical care a particular area of concern for energy impacted communities.[2] Industry response in these service areas is variable, and cooperation with local governments will doubtless be needed to maintain quality of life.

Lifestyle and cultural differences influence the way in which individuals perceive local attributes. Long-time residents in some isolated areas tend neither to expect nor to need the same set of services as newcomers, although in some areas newcomers and long-time residents have held similar opinions about local conditions.[3] Generally, opinions are affected by the contrasts in the lifestyles of ranchers and townspeople, energy development workers and farmers, Mormons and non-Mormons, and Indians and non-Indians. The clear-cut contrast between Indian and non-Indian values and communities is the most noticeable example of cultural differences.[4]

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[1] Mountain West Research. Construction Worker Profile, Final Report. Washington, D.C.: Old West Regional Commission, 1976; and Gilmore, J.S., and M.K. Duff. Boom Town Growth Management. Boulder, Colo.: Westview Press, 1976.

[2] Coleman, Sinclair. Physician Distribution and Rural Access to Medical Services, R-1887-HEW. Santa Monica, Calif.: Rand Corporation, 1976.

[3] See Mountain West Research. Construction Worker Profile, Final Report and Community Reports.

[4] See U.S., Department of the Interior, Bureau of Indian Affairs, Planning Support Group. Draft Environmental Impact Statement: Navajo-Exxon Uranium Development. Billings, Mont.: Bureau of Indian Affairs, 1976.

3.4.4 Regional Impacts

Region-wide social and economic impacts discussed in this section are population and economic impacts, and the effects of the personnel and capital requirements of energy development.

A. Population Impacts

One of the most important factors that will influence population change is the number and location of energy development personnel. Table 3-24 shows construction-related, operation-related, and total population increases for the eight state study region using low energy demand projections.[1] By the year 2000, the data in Table 3-24 indicate that the population will increase by 662,000 or about a 7 percent increase over the 1975 population of 9,551,000. Of this total increase, operation-related population is about 72 percent and construction-related is 28 percent.

The population impacts are not evenly distributed over the region. For example, the coal areas of the Northern Great Plains region (Montana, North Dakota, and Wyoming) are expected to have a considerably larger population increase than the other states in the West. This is due to the large scale and type of development as well as an estimated net in-migration of workers of 66 percent.[2] Further, the impacts vary by state. For example, within the Northern Great Plains, increases in population, above the 1975 level, are predicted to be from 27 percent (North Dakota) to 36 percent (Wyoming). In general, although the population increases from energy development will not be large region-wide, the development will largely take place far from metropolitan areas and will impact small towns and rural areas the most.

B. Economic Impacts

(1) Personal Income

Because of job opportunities, energy development is expected to generate new income for current residents and newcomers. Energy development is expected to increase the total real (constant dollar) income in the six state area by about 16 percent during the 25 year period (1975-2000). This is in addition to income growth from other sources. Most income growth will occur during the 1990's, when energy development alone would induce an annual growth rate of income of 1.06 percent.

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[1] Refer to Section 11.1.

[2] Refer to Section 11.4.2.

TABLE 3-24: POPULATION INCREASES IN WESTERN STATES AFTER 1975 DUE TO ENERGY DEVELOPMENT

YEAR	CONSTRUCTION-RELATED[a]	OPERATION-RELATED	OVERALL INCREASE
1980	31,600	45,000	76,700
1985	32,400	118,200	150,600
1990	20,900	157,200	178,100
2000	187,300	474,600	661,900

[a] Based on the average annual construction employment for the construction period of each facility and the projected number of facilities.

As with population, income gains are not evenly distributed among states. Over the 25 year period, Wyoming would experience the greatest relative gain (49 percent) and Utah the least (1.3 percent). By the per capita measure, the greatest absolute gain is expected in Montana ($630 per year), while Utah would have the least ($30 per year). These increases in per capita income would be due in large part to the construction phase of energy development.

Finally, additional impacts due to inflation are expected to occur. Increased wages will usually more than compensate for increased prices, but retirees and individuals with fixed incomes are likely to be adversely affected.

(2) Secondary Industries

Energy development will also affect the economic structure of the region by attracting secondary industries. Growth is expected for large industries linked directly to the energy facilities and for local and regional services industries responding to population growth.

Industrial expansion for "supplier" industries is expected to occur primarily outside the region, in existing northeastern or west coast industrial complexes; Salt Lake City is the most likely city in the study area to be affected. "User" industries (or those associated with processing the by-products of the energy facilities) are also expected, but are highly unpredictable in size and location. Some possible by-products for processing industries including sulfur, nahcolite (naturally occurring sodium bicarbonate), tar, and ammonia.[1] Whether user industries will be established in the region depends on the quantity of by-product produced. If there is not an adequate amount generated, they will tend to be transported out of the region for processing. For example, a minimum of 3-4 Lurgi plants is currently considered necessary to attract firms that would use their by-products.

Two types of service industries will evolve and expand as a result of energy developments: those that serve the needs of energy developers (e.g., machine shops, accounting firms, and supply houses) and those that are related to the population growth. In the case of service industries serving the energy developers, expansion is very difficult to predict since many energy developers and construction contractors provide these services themselves. However, impacts will probably occur in the larger cities such as Casper and Grand Junction. The second type of service industry (wholesale and retail trade) responds primarily to the growing population. In general, although the retail sector in small towns grows with population, the largest absolute growth will tend to concentrate in large centers.

(3) Expenditures and Revenues

Since much of the development of energy resources will occur in sparsely populated areas, small communities will face greatly expanded demands for services. Table 3-25 shows predicted investments for public facilities by the year 2000, for the Low Demand case. These range from $14.9 million (Utah) to $426 million (Montana) and are mostly for water supply, sewage treatment and school buildings. Local and state operating expenditures (above 1975 costs) for the year 2000 (Low Demand case) are also given in the table. The total new local operating expenditures for the region are expected to be $344.2 million; school districts account for 75 percent of this total. Local and state increases in annual expenditures are most extreme in Montana and North Dakota, and the Northern Great Plains states account for about 78 percent of the total state expenditures predicted for the region by 2000.

Estimated revenues, above the 1975 level, are also shown for the six states and the region in Table 3-25 for the year 2000. A total of $2.95 billion is likely to be collected in the six

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[1] For a further discussion of the various by-products from energy development facilities and their uses, see Section 11.4.3.

TABLE 3-25: PROJECTED LOCAL AND STATE EXPENDITURES AND REVENUES BY THE YEAR 2000

STATE	LOCAL CAPITAL[a] EXPENDITURES (millions of 1975 dollars)	LOCAL OPERATING[b] EXPENDITURES (millions of 1975 dollars per year)	CAPITAL AND OPERATING EXPENDITURES (millions of 1975 dollars per year)	REVENUES[c] (millions of 1975 dollars per year)
Colorado	193.2	50.7	84.1	224.9
New Mexico	101.8	20.3	33.7	299.1
Utah	14.9	4.8	8.0	30.5
Montana	426.0	107.6	178.6	1,318.3
North Dakota	324.7	91.1	151.3	489.4
Wyoming	292.6	69.7	115.6	592.6
Six State Total	1,353.2	344.2	571.3	2,954.8

[a] Value is the total expenditure of the 1975-2000 period.

[b] This is the amount required due to additional population, above 1975 levels.

[c] Includes severance taxes, property taxes, energy conversion taxes, and coal royalties.

state region, but revenues collected in Montana amount to 45 percent of the total.[1]

With the additional revenues from taxes levied on energy production and conversion, most state and local governments can be expected to derive more funds from new revenues than they expend on new costs. As emphasized above, the determinant of actual surplus or shortage, however, is the timing and distribution of funds. If states do not distribute revenues to local governments (particularly municipalities), or if impacted localities do not receive property tax benefits, then an overall surplus of funds at the state level is meaningless at the local level.

C. Personnel Availability

The question of personnel availability is addressed primarily on the regional and national levels because it is unlikely that local communities will be able to fill the skilled positions required by the energy technologies. The key point is whether rapid energy development could be delayed by a nationwide shortage of certain skilled personnel. Although shortages are not expected in broad engineering and managerial categories, the demand from energy development will tighten markets for specialized professions, such as mining engineers, boilermakers, and welders. The demand for certain personnel may also noticeably raise salaries. In general, the demand for all personnel can be met, but will require expanded training programs, either as formal education or in the form of apprenticeships.

D. Capital Availability

The development of western energy resources would require large investments. The four energy technologies which contribute most to capital demands are surface coal mining, mine-mouth power generation, coal gasification, and oil shale processing. By the year 2000, the gross investment for these facilities in the West is expected to be over $70 billion.

The capital requirements for the proposed energy facilities are not a large fraction of the total capital required nationally for plant and equipment (1.5 percent over the 25 year period with a maximum of 3.7 percent from 1991-2000). However, joint ventures and outside financing will likely be required because single companies are unlikely to have adequate capital to cover individual facilities.

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[1] This is due largely to Montana's relatively high coal severance tax of 30 percent.

3.4.5 Summary of Technological and Locational Factors

When a technology-related, impact-causing factor interacts with certain site-related conditions, social and economic impacts can be magnified. Potentially critical problems caused by energy technologies being located in the West are listed in Table 3-26 together with the combinations of technology and site related factors that cause them.

Coal synthetic fuels technologies (and to a lesser extent oil shale retorting and electric power generation) are relatively labor intensive. High labor intensity and high peak construction to operation labor ratios, in combination with small, isolated communities where institutional planning capacity and financial capabilities are inadequate, cause social impacts to be magnified into critical problems (e.g., inadequate housing, schools, roads, and health care).

A substantial number of the impacts on these communities can be alleviated (or even eliminated) if the development choice is to "strip and ship" the coal rather than to convert it to some other energy form at the mine-mouth. In fact, local communities might escape most of the stresses and strains associated with energy resource development if more of the raw resources were exported from, rather than converted within, the region. However, important fiscal disadvantages are associated with the export option. The most obvious disadvantage is that taxes based on the assessed valuation of large-scale conversion facilities and activities would accrue to nonwestern areas. If that tax gap is to be filled, the typical fiscal alternative would be to develop an extraction or severance tax that falls either directly or indirectly on mining activity. This would tend to raise the price of energy delivered to the conversion facility (e.g., a power plant near Chicago), perhaps putting the exporting state at a competitive disadvantage with states that have lower severance taxes. The extreme effect could be to drive mining companies to other states.

When mining is relatively labor intensive, as underground coal mining is, the negative economic impacts on state and local governments may be magnified. In such a case, the increased population would have to be served, but, as stated above, much of the tax base would have been exported together with the coal.

Scheduling multiple labor intensive technologies so that the rate of increase in demand for services escalates rapidly causes the same impact problems as those described above. However, the scheduling factor causes the problems to become critical for larger communities as well as small, isolated ones. Avoiding simultaneous scheduling of several energy developments, especially several conversion facilities, in an area may only be possible by slowing the overall rate of development of western resources.

TABLE 3-26: SUMMARY OF SOCIAL AND ECONOMIC PROBLEMS

SOCIAL AND ECONOMIC PROBLEMS	COMBINATIONS OF FACTORS THAT CAUSE THE PROBLEM	
	TECHNOLOGICAL	LOCATIONAL
Inadequate housing and services	High labor intensity for any one facility	Small isolated communities, inadequate institutional capacity and financial capability
Inadequate housing and services	Scheduling multiple labor intensive facilities simultaneously	Larger communities, inadequate institutional capacity and financial capability
Benefits accrue to newcomers rather than oldtimers	High labor intensity for any one facility	Small, untrained local labor force
Financial discontinuities, strained intergovernmental relations	High labor intensity and low capital intensity	Inadequate mechanisms for redistributing revenues between jurisdictions

The extent to which the local labor force can be tapped by the energy facility will largely determine the distribution of income benefits between long-time westerners and newcomers. Because of the specific skill mix and overall labor requirements, mining can generally draw on the local labor force for a significant percentage of labor requirements. On the other hand, the skills required for conversion facilities (especially during construction) are quite specialized and overall labor requirements are high. The percentage of newcomers required by them will be much greater than those for mining. Training programs aimed at the local labor force can alleviate the problem to some degree.

The combination of the capital intensity and labor intensity of a technology determines the relationship between financial benefits from development (in the form of tax revenues and personal income increases) and financial costs (in the form of housing, schools, and other services). While the financial benefits which accrue from conversion facilities generally exceed their financial cost, the jurisdictions which must bear the costs (usually cities and towns) often do not receive the benefit. Jurisdictional arrangements for distributing financial benefits vary by location. In states that do not have legislation enabling communities to act on their own or programs to provide funding assistance aimed at impacted communities, this income distribution problem will be critical and lead to strained intergovernmental relations.

3.5 ECOLOGICAL

HIGHLIGHTS

- **CRITICAL FACTORS**
  - *Five technological factors can significantly affect the ecological impacts of energy development: land requirements, water requirements, water effluents, labor intensity, and air emissions.*
  - *Four locational factors can also significantly affect these impacts: climate, topography, soils, and plant and animal communities.*
- **LAND REQUIREMENTS**
  - *Direct land use by surface mining can be 10 times greater than for underground mines and coal conversion facilities.*
  - *Surface coal mines in New Mexico and North Dakota use up to six times more land than do surface mines in Wyoming to produce the same amount of energy. Potential for reestablishing vegetation in reclaimed lands is higher in the Northern Great Plains than in the Rocky Mountains or Southwest.*

- *Land use to meet the needs of energy-related population growth generally produces more significant ecological impacts than does land used directly by the energy facilities.*

- *Land use by any single development generally disturbs only a small percentage of a habitat type; however, even a small disturbance can be significant if the habitat is a rare type, as aquatic habitat is in the study area.*

- **WATER REQUIREMENTS**

  - *Withdrawals of local surface water by any single conversion facility generally will not have a significant impact on aquatic habitat; western Colorado is an exception.*

  - *Withdrawals of local surface waters for multiple facilities at the same location could eliminate some sport fish from streams, alter the plant communities supporting other fish, and reduce riparian habitat.*

- **LABOR INTENSITY**

  - *The more labor intensive a technology, the more likely that ecological impacts will be significant as a result of land use, habitat fragmentation, water withdrawals, and recreation by new populations. Public lands, particularly those in a natural state, are likely to experience the greatest changes.*

- **EMISSIONS AND EFFLUENTS**

  - *In rough terrain, SO_2 levels produced by conversion facilities can result in acute local damage to vegetation.*

  - *Although the consequences are not adequately understood, trace elements in air emissions and water effluents can enter the ecosystem food web; for some substances such as mercury, concentrations in the tissue of carnivores already exceed government standards.*

3.5.1 Introduction

The severity of ecological impacts depends on the technology deployed and the type of ecosystem affected. For example, technologies differ in their land, water, and labor requirements, and sites differ in their climate, topography, soils, and plant and animal communities. Although many uncertainties exist regarding ecological impacts from energy development, several technological and site specific factors are identified which apparently can contribute to impacts.

3.5.2 Variations by Technologies

Six factors that vary among technologies can negatively affect ecosystems: land use, labor intensiveness, water requirements, water effluents, air emissions, and type of transportation system for the energy products.

A. Land Use

Direct ecological impacts are caused by land disturbances at mine and plant sites. These disturbances result in the temporary removal of vegetation and, therefore, animals dependent on the vegetation. Variations in land use by technology are compared in Table 3-27 for facilities deployed in our scenarios. Although land requirements for most conversion facilities are very similar on an energy-equivalent basis, a typical size power plant requires about three times more land than gasification facilities, and Synthoil liquefaction requires about twice as much as gasification. Land requirements are also large for TOSCO II oil shale retorting, largely because of spent shale disposal. Land use for underground coal mines is similar to that for conversion facilities; however, surface coal mines can require 10 times more land, depending on the seam thickness and heating value of the coal.

By eliminating, reducing, or changing vegetation, direct land use reduces the overall carrying capacity of an area, fragments habitat types, and may increase erosion. When carrying capacities are lowered, animal populations, such as deer and elk, may also be reduced. Fragmentation also reduces animal populations that range or migrate over large areas. Increased erosion will speed nutrient and runoff losses from affected areas within ecosystems. Thus, where nutrients or water already limit vegetation growth, erosion and limited water retention further reduce both plant growth and carrying capacity for animals.

Generally, the amount of land disturbed directly by any one mine-plant combination is small compared to the area of entire counties or the total amount of habitat in a region. Thus, the impacts resulting from direct land use occur locally; they have regional importance only when the habitat disturbed is rare or supports endangered species. For example, riparian ecosystems are rare in the West; five percent reduction in riparian habitat in a location has much greater impacts than eliminating five percent of a desert shrub community which is very common. Similarly, eliminating black-footed ferret habitat (an endangered species) has different implications than eliminating mule deer habitat.

TABLE 3-27: LAND USE BY TECHNOLOGY

TECHNOLOGY	SIZE	LAND USE: TYPICAL SIZE[a] (acres per 30 year life of facility)	ENERGY EQUIVALENT (acres per 10^{12} Btu in product)
Coal			
Power Plant	3,000 MWe	2,400	
Per Btu electric			1.2
Per Btu thermal			0.4
Lurgi Gasification	250 MMscfd	805	0.3
Synthane Gasification	250 MMscfd	805	0.3
Synthoil Liquefaction	100,000 bbl/day	2,060	0.4
Surface Mine[b]	12.2-19.2 MMtpy	3,300-25,200	0.6-4.4
Underground Mine[c]	12 MMtpy	1,760	0.3
Oil Shale			
TOSCO II Oil Shale Processing	50,000 bbl/day	2,150[d]	0.8
Underground Oil Shale Mine	26 MMtpy	500[e]	0.1
Modified in situ Oil Shale Processing	57,000 bbl/day	180[f]	0.06
Modified in situ Oil Shale Processing with Surface Retort	57,000 bbl/day	1,240[g]	0.4
Oil			
Conventional Crude Oil Extraction (well field) Enhanced Crude Oil	50,000 bbl/day	1,000	0.4
Gas			
Natural Gas Production/Processing	250 MMscfd	850	0.3
Uranium			
Underground Mine	1,100 mtpd (ore)	70	0.01
Surface Mine (open pit)	1,100 mtpd (ore)	3,450	
Mill	1,000 mtpy (yellowcake)	280	0.03
Solutional Mine-Mill	250 tpy (yellowcake)	200	
Geothermal	100 MWe	4-37	
Per Btu electric			0.06-0.5
Per Btu thermal			0.02-0.2

Btu = British thermal unit
MWe = megawatt-electric
MMscfd = million standard cubic feet per day
bbl/day = barrels per day

MMtpy = million tons per year
mtpd = metric tons per day
mtpy = metric tons per year
tpy = tons per year

[a] For facilities, this is the land required for the facility site. For surface mines, the 30 year life value was obtained by multiplying the number of acres stripped in 1 year by 30 years.

[b] This represents the size range for mines required to supply coal to a 3,000 MWe power plant.

[c] Includes only that portion of the mine site to be permanently occupied. At Kaiparowits, 30,000 acres will be subject to subsidence over the 30-year life of the mine. It is expected that nearly all of this land will be reclaimed and returned to productive use.

[d] Includes 650 acres for the retort site and 1,500 acres for spent shale disposal over 30 years.

[e] That portion of the mine site to be occupied by the surface structure.

[f] Includes land for the surface structure associated with the mine (100 acres) and in situ process (80 acres).

[g] Includes land for the surface structure associated with the mine (100 acres), surface retorting (240 acres), and spent shale disposal over 30 years (900 acres).

B. Labor Intensiveness

If reclamation attempts are successful, variation in the labor intensity of technologies may be more important than land used by the facilities or mines. Increased population contributes to air and water pollution, as well as increased land requirements for housing, transportation, service needs, and recreation. Conversion technologies are more labor intensive than mining. Surface mining is the least labor intensive energy technology deployed in our scenarios and gasification and crude oil production are the most labor intensive.[1]

The types of ecological impacts from population increases are similar to those caused by land use for facility siting. More housing, roads, and service activity fragment habitat into small parcels that are less usable by either resident or migratory species. Easier access to recreational areas often results in increased hunting. Recreational use can also increase erosion, damage vegetation, degrade aquatic habitat, and disturb terrestrial wildlife. Habitats which are most at risk are high alpine ecosystems (particularly lakes), high and middle-elevation streams and riparian habitats in deserts. Where public land is accessible to new urban populations, back-country recreation in the form of camping, hunting, fishing, and off-road vehicle (ORV) use will be extensive and can cause major ecological changes.

C. Water Requirements and Aquifer Interruption

The most pervasive ecological changes due to energy resource development will occur in streams and rivers that experience severe reductions in flow resulting from reservoirs, consumptive water use, groundwater depletion, and runoff interception. Differences in water requirements among technologies and opportunities to minimize water use can significantly affect ecological impacts.

As indicated in Section 3.3, electric power generation consumes the most water, and cooling represents the single largest part. Synthoil liquefaction requires less water than other conversion facilities; surface mining requirements (including irrigation) are an order of magnitude less than conversion facilities. Minimizing cooling water requirements by using combinations of wet and dry cooling can minimize the threat to aquatic ecosystems.

Water savings from the use of combinations of wet and dry rather than wet cooling were discussed in Section 3.3. Total consumptive water use by these technologies in the UCRB can be reduced by about 20 percent with the use of wet/dry cooling. The largest percentage reductions can be obtained for electric power plants; up to 20,340 acre-ft can be saved per year for a 3,000 MWe plant. While the water saved for synthetic fuel facilities is not nearly as much, it can be large enough to reduce impacts to aquatic ecosystems at some sites in our eight-state study area. When the savings are aggregated for several facilities in the same watershed, the benefits to aquatic ecosystems are even more important.

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[1] Data on the labor intensiveness of the technologies deployed in our scenario are presented in Section 3.4.

Impacts caused by flow reductions will vary seasonally. Normal flows in spring will be sufficient for fish migration and spawning; lower flows during summer will reduce habitat and water quality, thereby interfering with the growth and survival of some fishes; and low flows in winter can cause ice-scouring, thereby reducing the population of aquatic invertebrates that support fish in spring and summer. Flow reductions also narrow the margin of marshlike habitat which parallels many streams. This riparian habitat supports large and diverse communities of waterfowl and shorebirds. Since riparian habitat is particularly scarce in the eight-state area, any reduction constitutes a large percentage loss in its availability.

Both coal and oil shale mines require dewatering as mining progresses. The marsh habitat along stream margins may be the interface of groundwater with surface water, or may be affected by springs. To the extent that aquifers are dewatered, habitat will be narrowed or eliminated.

D. Wastewater Effluents

Wastewater for conversion facilities is generally impounded in on-site evaporative holding ponds. Both the quantity and content of the effluent discharged to these ponds will vary by technology (see Section 3.3). Of coal conversion technologies, Synthoil liquefaction produces the largest quantities of effluents and Lurgi gasification the least.

Impounded effluents from power plants are primarily scrubber sludge and ash, while effluents from synthetic fuel facilities are primarily ash. Effluents from synthetic fuels facilities also contain heavy metals such as nickel, zinc, and lead as well as potentially cancer-producing polynuclear aromatic hydrocarbons (PAH). If the dikes around impoundments fail or erode, the wastes could destroy some stream communities, reducing productivity for several years.[1] Additionally, some metals may seep or leak through the liners of the ponds even if they are properly designed and maintained, thus contaminating groundwater and surface water.

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[1] U.S., Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado. Washington, D.C.: Bureau of Land Management, 1975.

Heavy metals and organic compounds can also be a problem. Heavy metals can contaminate stream ecosystems where they are cycled in and through food webs. Both aquatic plants an animals have low tolerance to heavy metals. If water is used for drinking and/or fish taken from the streams are eaten by people, contamination carries with it potential health hazards. However, the extent to which contamination and food web uptake is likely to occur is uncertain.

E. Air Emissions

The most ecologically dangerous criteria pollutants produced by energy facilities appear to be SO_2 and NO_x. Maximum ground-level concentrations of SO_2 produced by conversion facilities are known to cause both chronic and acute damage to sensitive native and crop plants.[1] Although maximum worst case concentrations will occur infrequently, SO_2 emissions from electric power plants in areas of rugged terrain, such as southern Utah, and sulfur emissions from oil shale facilities in western Colorado can subject vegetation to acute damage.

Mercury is contained in some stack gases from power plants and coal synthetic fuels facilities. While the amount of mercury emissions is uncertain, any additional levels could worsen ecological problems in some areas. For example, in the Lake Powell area, mercury concentrations in some predatory fish already exceed Food and Drug Administration standards for safe human consumption.[2] Projections based on Lake Powell studies indicate that energy development might cause mercury increases between 10 and 50 percent, depending on the number of facilities and the composition of the coals being used.[1]

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[1] See Hertzendorf, M.D. Air Pollution Control Guidebook to U.S. Regulations. Westport, Conn.: Technomic, 1973, pp. 154-55; U.S., Department of Health, Education, and Welfare, Public Health Service. "Effects of Sulfur Dioxides in the Atmosphere on Vegetation," in Air Quality Criteria for Sulfur Oxides. Washington, D.C.: Public Health Service, 1969, pp. 61-69; and Benedict, H.M., C.J. Miller, and R.E. Olson. Economic Impact of Air Pollution on Plants in the United States. Menlo Park, Calif.: Stanford Research Institute, 1971, pp. 40-46.

[2] Standiford, D.R., L.D. Potter, and D.C. Kidd. Mercury in the Lake Powell Ecosystem, Lake Powell Research Project Bulletin No. 1. Los Angeles, Calif.: University of California, Institute of Geophysics and Planetary Physics, 1973, p. 16.

F. Transportation Technologies

Transportation systems for the technologies considered in this study include unit trains, slurry pipelines, gas and oil pipelines, and EHV transmission lines. Each of these transportation modes can produce ecological impacts. Unit trains are potentially the most destructive to biological resources. Rail lines built for heavy unit train traffic pose a hazard to large animals (e.g., antelope) which move in herds over large areas during the year. Since some railroad right-of-way is likely to be fenced on both sides to protect livestock, the migration of some herds over their accustomed ranges will be restricted if new lines are built. Thus, crossings may have to be constructed to allow them to pass. If fences are not built, animals can be killed by the trains.[2]

Other transport modes are less disruptive to wildlife. Pipelines result in negligible impacts.[3] EHV transmission lines alter habitat types, reducing forested area for example. However, this alteration may add beneficial ecological diversity in some regions. At present, there is inadequate information about electric fields from EHV lines to assess impacts.

3.5.3 Variations by Existing Conditions

The severity of impacts summarized in the previous section will also depend on the ecological characteristics of the site where technologies are deployed. Important site specific variables are grouped into three categories in this discussion: physical and biological characteristics, such as climate, soils, and plant and animal communities, which determine ecosystem stability and resiliency; present land use characteristics, such as the extent to which a region is pristine or wilderness and the extent of public land ownership; and instream flow, which affects dilution of polluted runoff.

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[1] Standiford, D.R., L.D. Potter, and D.C. Kidd. Mercury in the Lake Powell Ecosystem, Lake Powell Research Project Bulletin No. 1. Los Angeles, Calif.: University of California, Institute of Geophysics and Planetary Physics, 1973, p. 16.

[2] See Sections 3.7 and 11.6 for a more extensive description of levels of unit train traffic and the problem trains can pose for animals.

[3] Slurry pipelines require 740 acre-ft of water per ton of coal and can contribute to the water impacts discussed above.

A. Ecosystem Stability and Resiliency

Both the reclamation potential of a site and the response of an ecosystem to exposure to chronic air pollutants depend on the ecosystem's stability and resiliency. Stability is the ability of a system to remain unchanged under stressful conditions, whereas resiliency is the ability of a system to recover following a stress-induced change. The response of ecosystems in the West to impacts such as fragmentation, addition of mineral elements, nutrient losses, and chronic exposure to air pollutants is largely a function of their stability. Reclamation potential is largely a function of resiliency.

(1) Climate

Average rainfall data for three areas within the eight-state study area are given in Table 3-28. Both total amounts and the seasonal distribution are included. The Southwest receives the least amount of rainfall overall. In the Rocky Mountain and Northern Great Plains, total rainfall is similar, but rainfall during the summer growing season in the Northern Great Plains is twice that of the Rocky Mountains. Since the amount of rainfall during the growing season is probably the single most important factor affecting reclamation potential, reclamation will be most easily accomplished in the Northern Great Plains and most difficult in the Southwest. Moreover, reclamation problems will be worsened in some areas of the Southwest, where land requirements for surface coal mines can be very large. As shown in Table 3-29, land requirements for a typical size mine at Navajo/Farmington are much larger than those at Colstrip or Gillette; hence, water requirements for reclamation will also be higher.

Using present reclamation techniques, areas averaging 10 or more inches of rainfall per year can generally support plant regrowth without supplemental irrigation.[1] In most of the semiarid Southwest, rainfall is regularly less than 10 inches and varies widely from year to year. Periodic dry periods lasting up to several years further curtail successful revegetation. The seasonal distribution of rainfall is perhaps the most critical variable; for example, a lack of precipitation shortly after planting can reduce seedling success, and a difference of only 1-2 inches over the entire growing season will have significant consequences. Because most reclamation studies have been initiated

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[1] National Academy of Sciences. Rehabilitation Potential of Western Coal Lands, a report to the Energy Policy Project of the Ford Foundation. Cambridge, Mass.: Ballinger, 1974; and Packer, Paul E. Rehabilitation Potentials and Limitations of Surface-Mined Land in the Northern Great Plains, General Technical Report INT-14. Ogden, Utah: U.S., Department of Agriculture, Forest Service, Intermountain Forest and Range Experiment Station, 1974.

TABLE 3-28: RAINFALL AVERAGES IN THE WEST

REGION	RAINFALL[a] (inches)		
	WINTER	SUMMER	ANNUAL
Northern Great Plains	<5	10-20	10-20
Rocky Mountains	5-10	5-10	10-20
Southwest	<5	<5	<10

< = less than

[a] Espenshade, Edward B., ed. Goode's World Atlas, 13th ed. Chicago, Ill.: Rand McNally, 1971; winter corresponds to November 1/April 30; summer corresponds to May 1/October 31.

TABLE 3-29: LAND USE FOR SURFACE COAL MINES BY SITE[a]

SITE	TYPICAL SIZE MINE[b] (acres over 30 years)	ENERGY EQUIVALENT (acres per 10^{12} Btu)
Navajo/Farmington	24,900	4.3
Gillette	3,300	0.6
Colstrip	10,200	1.7
Beulah	25,200	4.4

[a] Seam thickness and heating values assumed: Navajo/Farmington--10.3 feet, 3,600 Btu per pound; Gillette--64 feet, 8,000 Btu per pound; Colstrip--28 feet, 8,600 Btu per pound; Beulah--13 feet, 6,950 Btu per pound.

[b] In all cases, the mine size assumed supports a 3,000-megawatt-electric power plant.

since 1970, there has been no opportunity to observe precisely how rainfall variations affect long-term reclamation success.[1]

(2) Soils

Natural surface soils vary greatly within the eight-state study area; even a single mine site may contain several soil types that differ in suitability for reclamation. In the Northern Great Plains, soils are generally well developed with adequate nutrient and organic matter. These soils have a high potential for use in mine-spoil revegetation.

Three major soil types are found in coal-producing regions of the Central Rocky Mountains: soils of dry sagebrush areas which are generally poor in organic matter; rocky or barren badlands soils which are less than 20 inches deep and subject to water erosion; and loamy, easily tilled soils which are rich in organic matter. These latter soils are usually found on western Colorado coal lands and are often farmed for dryland crops. All three types of soils will probably require irrigation for successful reclamation.

Soils in Arizona and New Mexico are generally poorly developed, have an unsatisfactory moisture-holding capacity, and have a high salt content. Moreover, these soils have become sandy and eroded through overgrazing. Drifting and blowing soils in these areas can easily bury seedlings or reduce plant cover by abrasion.

(3) Plant and Animal Communities

The dominant plant communities found in three areas of the eight western states are given in Table 3-30. For each area, these communities are listed in increasing order of structural complexity and productivity. In the Rocky Mountains and Southwest, increased productivity generally corresponds to higher elevation and rainfall. For example, in the Southwest, the desert shrub community is located at low elevations where rainfall is often less than five inches, whereas the piñon-juniper woodland is located at higher elevations where rainfall is often greater than 10 inches.

In general, the more complex a plant community is, the more stable but less resilient it is. A grassland is generally not as stable as a forest and its ability to remain unchanged in the face of stresses is not as great as that of the forest. Thus,

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[1] Farmer, E.E., et al. Revegetation Research on the Decker Coal Mine in Southeastern Montana, Research Paper INT-612. Ogden, Utah: U.S., Department of Agriculture, Forest Service, Intermountain Forest and Range Experiment Station, 1974.

TABLE 3-30: PLANT COMMUNITIES AND THEIR PRODUCTIVITY

REGION	PREDOMINANT PLANT COMMUNITIES	PRIMARY PRODUCTION[a] (grams per square meter per year)
Northern Great Plains	Short grass prairie	600-900
	Midgrass prairie	600-1,100
	Bottomland forest	1,000-2,000
	Pine savanna	1,000-2,000
Rocky Mountains	Desert shrub	100-200
	Piñon-juniper woodland	500-1,000
	Mountain shrub	600-700
	Mountain meadows	700-1,100
	Coniferous forests	900-2,000
Southwest	Desert shrub	0-200
	Desert grassland	200-500
	Piñon-juniper woodland	500-1,000

[a] Ranges given represent rounded estimates from Cooper, J.P., ed. Photosynthesis and Productivity in Different Environments, International Biological Programme 3. London, England: Cambridge University Press, 1975. In this context, primary production refers to the "net" production of organic matter (including root and shoot growth) by the plant community; that is, it measures the rate at which solar energy is converted to organic matter.

overgrazed grasslands often revert to desert shrub communities. On the other hand, a grassland can more readily reestablish itself after surface mining than forest can. Similarly, it is easier to reestablish a desert shrub community than a grassland.

The productivity of a plant community measures the rate at which plants produce organic matter and support animals. Soil characteristics and the seasonal distribution of rainfall are the most critical factors limiting this rate. Irrigating reclaimed land allows higher primary production rates and faster revegetation. However, an irrigated reclamation site may be limited by soil nutrients or by unusually high concentrations of salts. This appears more likely in the Southwest.

B. The Character of Present Land Use

Changes in wilderness areas can occur rapidly as new populations enter a development area. Energy developments in northern Wyoming, western Colorado, and southern Utah are particularly close to national parks and scenic and wilderness areas. Particularly in southern Utah and western Colorado, both residents and visitors generally expect to encounter native plant communities, wildlife, and scenic vistas. On the other hand, land in the Northern Great Plains is largely agricultural. Thus, the nature of the ecological impacts will be different than those of the Rocky Mountain areas.

Availability of public land (such as national forests and parks, wildlife refuges, and wilderness areas) in the vicinity of energy development also influences ecological impacts. The federal government owns 87 percent of the land in the area around Kaiparowits/Escalante, 70 percent around Rifle, 39 percent around Navajo/Farmington, an additional 60 percent around Gillette, and 5 percent around Colstrip and Beulah. Public access to national forests has few restrictions. Where public land is accessible to populations associated with energy development, back-country recreation in the form of camping, hunting, fishing, and ORV use will increase. Although valued by residents, unrestricted or unenforced recreation potentially can cause ecological damage, including damage to wildlife habitat and alterations in the natural state of wilderness areas.

C. Stream Flow

Impacts on aquatic ecosystems will probably occur in the San Juan Basin, in the Utah-Colorado oil shale area, and, in the Yellowstone River Basin. Growth in agricultural irrigation and energy developments may add nutrient-, pesticide-, and silt-laden runoff to these river basins. Increased withdrawals for agriculture and energy development will reduce flows and concentrate existing pollution levels.

The Yellowstone River Basin could experience withdrawals from the river itself or its tributaries amounting to about 22 percent of typical low flows, depending on the use of reservoirs to regulate discharge. From Billings, Montana to the Missouri confluence, the Yellowstone River is free-flowing; there is now strong public sentiment in favor of keeping it free of dams and restricting industrial uses.[1] Impoundments on tributaries to the Yellowstone are likely to interfere with the spawning movements of several fish indigenous to the UMRB (e.g., the paddlefish, shovelnose sturgeon, and pallid sturgeon).

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[1] Montana, Department of Natural Resources and Conservation, Water Resources Division. Which Way? The Future of Yellowstone Water, Draft. Helena, Mont.: Montana, Department of Natural Resources and Conservation, 1976.

3.5.4 Regional Impacts

Development poses two major ecological stresses on the regional level: consumptive water use, and changes in land-use patterns.

Regional impacts on aquatic and riparian habitats are most likely to result from water shortages. As discussed in Section 3.3, total demands for water in the UCRB by the year 2000 are likely to exceed that not currently used (approximately two million acre-ft/yr). If this occurs, or if large percentages of available flows are withdrawn, damage to aquatic species could occur throughout the basin because concentrations of pollution would increase. These problems are much less likely for the Upper Missouri, where total basin flows are well in excess of expected withdrawals.

Use of land for energy conversion facilities, surface mines, and increased population could also damage terrestrial ecosystems on a regional level. Table 3-31 shows regional land requirements for energy facilities (not including mines) and for urban growth. About 70,000 acres of land will be required in the Rocky Mountain area. Energy conversion facilities account for about 73 percent of this and urban land about 27 percent. About 130,000 acres will be disturbed in the Northern Great Plains. Energy facilities and urban growth account for about equal proportions of this. Population increases will be larger in this area because more labor-intensive synfuel facilities are expected.

At the aggregate level, as many facilities are sited in one location, direct land use can affect or eliminate a large percentage of habitat types and result in significant reductions in carrying capacity. For example, development of one TOSCO II oil shale retorting facility disturbs only 0.3 percent of the 150 square mile area between Parachute Creek, Rifle, and the Colorado River in Garfield County. Construction of 10 such facilities would disturb more than 30 percent. Ecological impacts tend to increase exponentially with such expansion. Entire populations of animal species such as deer and elk could be eliminated in these locations, and their range in the West will be reduced.

3.5.5 Summary of Technological and Locational Factors

This summary identifies technology-location combinations that cause significant ecological problems (Table 3-32). Overall ecological degradation is increased when the land use affects habitat that is not abundant (e.g., riparian or unique habitat used by endangered species or by wildlife during some part of their life cycle). These habitats will be most threatened by labor-intensive technologies, primarily liquefaction and gasification, which result in the largest population increases and by

TABLE 3-31: LAND USE BY REGION IN THE YEAR 2000
(Low Demand case)

USE	ROCKY MOUNTAIN REGION[a] (39,726,720 acres)		NORTHERN GREAT PLAINS[b] (150,282,880 acres)	
Energy facilities	51,175	(0.13%)	65,615	(0.13%)
Urban land	18,805	(0.05%)	63,301	(0.13%)
Total	69,980	(0.18%)	128,916	(0.26%)

[a] Area includes Garfield, Mesa, Rio Blanco, and Huerfano counties in Colorado; Kane, Garfield, Uintah, and Grand counties in Utah; and San Juan, McKinley, Valencia, Lea, Eddy, Roosevelt, and Chavez counties in New Mexico.

[b] Area includes Bighorn, Powder River, and Rosebud counties in Montana; Campbell, Johnson, Sheridan, Converse, Natrona, Carbon, Fremont, and Sweetwater counties in Wyoming; and Dunn, Mercer, McLean, Oliver, Billings, Bowman, Hettinger, McKenzie, Slope, Stark, and Williams counties in North Dakota.

surface coal mining in areas where coal seams are thin (e.g., Farmington) and where the coal has a low heating value (e.g., Beulah). Land use by multiple surface coal mines and oil shale facilities at a site can affect a large percentage of total habitat at that site, resulting in habitat fragmentation which can eliminate wildlife and endangered species. These impacts will be less likely if land is successfully reclaimed. Although much uncertainty exists about reclamation potential throughout the study area, the most difficulty will apparently occur in the arid Southwest because of low average rainfall. Expanding energy development and related population growth will threaten natural wilderness areas, particularly around areas which have not experienced previous rapid growth. Energy developments in southern Utah, western Colorado, and northern Wyoming present the biggest threat to wilderness areas and natural ecosystems.

Water-intensive technologies, particularly electric power generation, located where stream flows are marginally adequate (the San Juan Basin, western Colorado, and to a lesser extent the Yellowstone Basin) will reduce or eliminate sport fish populations. Domestic wastewater discharged into streams can change plant and animal populations, and runoff or seepage from on-site eavporative holding ponds can further degrade stream and lake habitat.

TABLE 3-32: SUMMARY OF ECOLOGICAL PROBLEMS

ECOLOGICAL PROBLEMS	COMBINATION OF FACTORS THAT CAUSE THE PROBLEM	
	TECHNOLOGICAL	LOCATIONAL
Local ecological degradation, species elimination or extinction	Labor-intensive technology; surface coal mining or oil shale mining.	Unique or rare habitat; low heating value of coal and thin seams
Loss of ecosystems and associated wildlife through habitat fragmentation	Labor intensive technology; land use by multiple surface mines	Low yearly rainfall; proximity to wilderness areas
Reduction or elimination of sport fish, aquatic habitat, and streamside ecosystems	Water intensive conversion facilities	Limited and seasonal stream flow, limited riparian habitat
Acute and chronic damage to vegetation	Air emissions by conversion facilities	Rugged terrain
Interruption of migration, increased accidental kills	Rail transport of coal	Migratory mammal routes

Episodic ground-level SO_2 concentrations from air emissions by electric power plants and oil shale facilities can be high enough to cause chronic and acute damage to plant communities in areas where the terrain is rugged, most notably in southern Utah and western Colorado.

Railroads cause more ecological impacts than any other transportation alternatives. Where rail transport crosses migratory mammal routes, changed migration patterns will occur and accidental kills will increase.

3.6 HEALTH EFFECTS

HIGHLIGHTS

- **CRITICAL FACTORS**
  - *Two main technological factors can significantly affect the public health impacts of energy development: The quantity and composition of air emissions, and the quantity and composition of water effluents. The type of extraction technology, principally mining, affects the risks to worker safety.*
  - *Six locational factors can also significantly affect these impacts: composition and type of the energy resource, population characteristics, topography, meteorological conditions, existing health care delivery systems, and safety regulations.*
- **POTENTIAL PUBLIC HEALTH RISKS**
  - *Coal-fired power plants and synthetic fuel facilities of the size hypothesized and with attainable emission controls do not cause federal primary ambient SO_2, particulate, NO_2, and CO standards to be violated.*
  - *If a 3 percent sulfur to sulfates conversion rate is assumed, sulfate levels attributable to energy development are not expected to exceed the concentrations known to cause disease. However, if a 5 percent conversion rate is assumed, sulfate levels at some sites will be high enough to aggravate asthmatics. A conversion rate of 10 percent could result in chronic and acute respiratory disease.*
  - *The federal standards for NO_2 are not projected to be violated; however, short term peak concentrations from power plants and associated urban growth are projected to exceed concentrations that have been related to increased respiratory illness.*

- *The federal primary air standard for HC will be violated by the hypothesized coal liquefaction, oil shale retorting, natural gas facilities, and by urban sources. Concentrations could be as much as 240 times the standard. Oxidants produced from these HC emissions can constitute a public health risk.*

- *The various energy technologies can release low concentrations of a variety of toxic trace materials such as mercury, cadmium, and uranium. These trace emissions can represent a long term risk to human health, but there is great uncertainty as to the magnitude of these effects.*

• POTENTIAL OCCUPATIONAL SAFETY AND HEALTH HAZARDS

- *Occupational safety hazards, measured as frequency of death and injury, are greatest for underground coal and uranium mines.*

- *Worker exposure to materials causing respiratory disease and cancer poses occupational health risks. Black lung disease in underground coal mines and lung cancer in underground uranium mines are well documented health risks. Cancer causing HC will be present in synthetic fuel facilities but estimates of worker exposure are highly uncertain.*

3.6.1 Introduction

The risk that energy development poses for human health depend on the technologies deployed and the site-specific conditions under which development takes place. It should be noted, however, that generally there is great uncertainty regarding the identification of health impacts. Health effects can be as clear-cut as increased mortality from mine accidents or as difficult to ascertain as small increases in birth defects or in the incidence of cancer due to the release of low concentrations of toxic materials. This section summarizes the technological and locational factors that can lead to health hazards, even though in many cases the magnitutde or seriousness of the health effect is unknown. Impacts on public health as well as impacts on occupational health and safety are discussed.

3.6.2 Variations by Technologies

A. Public Health Impacts

As summarized in previous sections on air and water impacts, the energy resource development technologies vary in terms of the air emissions and water effluents they produce. These residual emission rates largely account for the potential public health impacts of energy development. This section summarizes the discussion in Chapter 10 concerning the implications for human health of SO_2 and sulfates, particulates, HC, oxidants, NO_x, trace elements, and radioactive materials. They will be discussed separately, although adverse health effects often result from a complex of emitted pollutants rather than from a single pollutant acting by itself.

(1) SO_2 and Sulfates

Energy conversion facilities, particularly power plants, will contribute to higher SO_2 levels. However, in the scenarios studied, the increase in SO_2 caused both by energy facilities and associated population growth will generally be below the federal primary ambient air standards designed to protect human health. Nevertheless, due to sulfate formation, which is currently not covered by federal ambient air standards, these levels of SO_2 emissions could represent a health hazard. Evidence is accumulating that the sulfates into which SO_2 is transformed pose the greatest potential for harmful health effects. Estimates of conversion rates vary from 1 to 20 percent per hour;[1] however, rates of from 1 to 3 percent per hour are commonly estimated for SO emissions from coal-fired boilers. Table 3-33 gives the sulfate concentrations projected for the six site-specific scenarios, assuming four different conversion rates. For perspective, sulfate levels known to cause disease are also included in the table. As indicated, conversion rates of less than three percent do not cause sulfate concentrations to be in excess of those which are known to cause a health effect. Conversion rates of 5 percent result in concentrations at three sites which exceed those known to aggravate asthmatics, and conversion rates of 10 percent would clearly result in health hazards.

(2) Particulates

Particulate emissions can vary widely by technology. Even with 99 percent particulate removal, electric power plants emit more particulates than any other conversion facility. However, in no case examined does a power plant alone cause primary ambient air standards for particulates to be violated.

Nevertheless, because particulate removal systems trap larger particles more efficiently than smaller particles, coal-fired power plants can still represent a significant health risk. With 99 percent efficient particulate removal, particles will

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[1] U.S., Congress, House of Representatives, Committee on Science and Technology, Subcommittee on Environment and the Atmosphere. Review of Research Related to Sulfates in the Atmosphere, Committee Print. Washington, D.C.: Government Printing Office, 1976.

TABLE 3-33: SULFATE CONCENTRATIONS AND THEIR HEALTH EFFECTS
(micrograms per cubic meter)

CASE	CONVERSION RATES (% per hour)			
	1	3	5	10
Scenario[a]				
Kaiparowits/Escalante	2.2	6.6	11.0	22.0
Navajo/Farmington	0.8	2.4	4.0	8.0
Rifle	1.5	4.5	7.5	15.0
Gillette	0.5	1.5	2.5	5.0
Colstrip	0.9	2.7	4.5	9.0
Beulah	1.1	3.3	5.5	11.0
Health Effects[b]				
Aggravation of asthma	6-10			
Increased chronic bronchitis	14			
Increased acute respiratory disease	10-25[c]			

[a] Based on highest peak concentration including existing ambient concentration (see Chapters 4-9).

[b] U.S., Environmental Protection Agency. Position Paper on Regulation of Atmospheric Sulfates, EPA 450/2-75-007. Research Triangle Park, N.C.: National Environmental Research Center, 1975.

[c] Finklea, J.F., et al. Health Effects of Increasing Sulfur Oxides Emissions, Draft. Washington, D.C.: U.S., Environmental Protection Agency, 1975. Cited in U.S., Council on Environmental Quality. Environmental Quality, Sixth Annual Report. Washington, D.C.: Government Printing Office, 1975, p. 332.

have a mean diameter of 1-3 microns. These particles can penetrate deeply into the respiratory tract, and about 30 percent of those penetrating will be deposited in the pulmonary alveoli where they can have the greatest adverse effects.[1] In addition, these fine particulates are especially amenable to absorption of toxic materials (particularly trace metals) which pose an additional health hazard.

(3) NO_2

The major contributors of NO_2 and other NO_x in the scenarios of this study are power plants. Peak 24-hour concentrations of NO_2 in the vicinity of power plants in the six scenario locations are given in Table 3-34. Peak concentrations (24-hour average) projected in 1990 for urban areas are also included. It should be noted that the federal primary standard is only on an annual average basis and is set at 100 $\mu g/m^3$. However, acute health effects (lung irritations) are possible when NO_2 concentrations are 1000 $\mu g/m^3$ (projected to be exceeded only at the Escalante power plant). Increased respiratory illness, however, may occur at average 24-hour concentrations of 100-200 $\mu g/m^3$. Concentrations predicted to occur around urban areas exceed this limit in 1990 at Farmington and Gillette. Peak 24-hour NO_2 concentrations in the vicinity of power plants are all above the 100 $\mu g/m^3$ level indicating the possibility of adverse health affects for populations living in the vicinity of large power plants.

(4) HC and Oxidants

As indicated in Table 3-35, the federal primary ambient air standard for HC is exceeded as a result of emissions from Synthoil liquefaction, TOSCO II oil shale retorting, and nautral gas production facilities as well as from urban sources. Contributions from power plant operations are minor. HC emissions from the hypothesized conversion facilities exceed the primary standard by seven times (natural gas) to 240 times (TOSCO II). The population related HC emissions (mainly from automobiles) are projected to exceed the primary standard after 1980 at all sites.

The extent to which these HC emissions represent a health risk is very uncertain. Some of the HC emitted are carcinogenic, such as PAH, and others can become carcinogenic in combination with other compounds in the atmosphere (e.g., SO_2 and particulates). Since these HC emissions are primarily "fugitive" (from valves, fittings, and seals) they are difficult to control.

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[1] See, for example, Southern Research Institute. A Survey of Technical Information Related to Fine Particulate Control. Springfield, Va.: National Technical Information Service, 1975.

TABLE 3-34: PEAK OXIDES OF NITROGEN CONCENTRATIONS FOR SCENARIO LOCATIONS
(24-hour average measured in micrograms per cubic meter)

LOCATION	SOURCE	
	URBAN (1990)	POWER PLANT[a]
Kaiparowits	88	130-220
Escalante	NC	760-1260
Farmington	163	125-210
Rifle (Grand Valley)	57	380-630
Gillette	140	115-190
Colstrip	54	120-200
Beulah	42	170-280

NC = not calculated

[a] Range indicates 0-40 percent removal of NO_x by scrubber.

In addition, HC contribute to the formation of oxidants that can cause irritation to the eyes and throats of humans. Oxidants are one of the reactants in the formation of photochemical smog (a reaction of HC, NO_x, and other compounds, activated by solar energy).

(5) Radioactivity

Exposure to radiation from energy facilities considered in this study may originate from coal, uranium, and oil shale facilities. Current information is available only for exposures to radioactive materials from coal and uranium facilities.

Radioactivity in coal is highly variable. The major source of radioactivity is Radium 226. After the coal is burned, it becomes concentrated in the ash. If the ash is accumulated in piles, it may contaminate surface water or be blown as dust. In addition, other radioactive gaseous products are released into the air. Inhalation of airborn radioactive substances is suspected of causing lung cancer. However, based on the levels

TABLE 3-35: SELECTED AMBIENT 3-HOUR HYDROCARBON CONCENTRATIONS WHICH RESULT FROM URBAN EXPANSION AND ENERGY FACILITIES (micrograms per cubic meter)

	PEAK CONCENTRATIONS		
	1980	1990	2000
Urban Expansion[a]			
Kaiparowits	NC	481	NC
Farmington	750	871	900
Rifle	102	571	NC
Gillette	660	780	871
Colstrip	210	270	351
Beulah	180	210	NC
Conversion Facilities			
Synthoil Liquefaction			
Farmington	21,500		
Gillette	25,100		
Colstrip	17,200		
TOSCO II Oil Shale			
Rifle	38,540		
Natural Gas Production			
Gillette	1,087		
Federal 3-hour Primary HC Standard	160		

NC = not calculated HC = hydrocarbon

[a] Urban expansion represents that expected in the years indicated (except Beulah which is 1985, 1995) as a result of the energy development assumed at six sites (see Chapters 4-9).

of radioactivity emitted from coal-fired power plants and its widespread distribution, the health risks due to radioactivity are believed to be very small.

On the other hand, radioactivity emissions from uranium mining and milling operations pose a more serious public health problem. One study indicated that a significant health risk from radioactivity exposure exists up to distances of one kilometer from uranium tailing piles. In the vicinity of mines and mills near Grants, New Mexico, radon levels are up to 10 times the accepted standards.[1] Uranium mills also release uranium particulates into the atmosphere, and are the source of the major uranium exposures to nearby populations.

(6) Trace Materials

The development of western energy will result in a wide range of trace materials being emitted to the atmosphere and discharged in effluents to holding ponds or receiving waters. Some of these trace materials are much more toxic on a by-weight basis than are criteria pollutants. When inhaled or injested, they may cause problems that vary in seriousness from irritation to death.

The sources of potentially toxic trace substances include mine wastes and the waste streams and emissions from combustion and conversion facilities. While they may occur in small quantities in fuels, trace elements may become more concentrated in waste streams. Additional concentration of these elements may occur as they are assimilated into food webs in the environment. Intake levels of some trace elements by certain animals (for example, cadmium, mercury, and lead) already exceed tolerable limits[2] and increased trace element emissions and discharges can significantly affect the likelihood of health problems.

B. Impact on Occupational Safety and Health

Many of the factors discussed above that affect public health can be considered occupational health hazards as well. In addition, workers are exposed to job related hazards such as high pressure vessels, complex machinery, and close contact with toxic substances. These and related health and safety risks vary among jobs and technologies. Two major categories of risk exist: safety risks that may result in acute or immediate trauma that produces death or injury; and longer term health risks from chronic exposure to residuals within the boundaries of energy facilities.

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[1] Evaluation of this problem and health risk is being conducted by the New Mexico Environmental Improvement Agency.

[2] As defined by World Health Organization/Food and Agriculture Organization.

(1) Safety

Safety risks occur in all phases of western energy development. Existing data (Table 3-38) indicate that the frequency of death in underground coal mining is several times greater than other phases of energy development, both on a per worker and on a per Btu produced basis. However, existing data are difficult to compare. Accident rates depend on type and location of the coal mine and on definitions used to differentiate among different aspects of mining. Coal extraction, for example, frequently includes workers in coal cleaning facilities, a less hazardous environment. In addition, specific coal extraction technologies differ; a number of western mines, for example, use longwall mining, whereas more eastern mines use room and pillar mining. Thus, comparable quantitative safety information on western energy occupational risks are not available.

Also, occupational health statistics are gathered by different agencies of government for different fuel cycles, making comparisons among technologies difficult. Thus, conclusions based on statistical accident data should be made cautiously.

Although not shown in Table 3-36, transporting coal results in more workdays lost (2,340 workdays lost per 1,000 MWe capacity each year) than surface coal mining (499). The long transportation distances associated with western energy development make this significant accident rate data even more critical.

The comparisons in Table 3-36 also indicate that nonfatal accidents in uranium mills can be significant, as these mills are apparently among the most injury prone environments on a per worker basis. Data are not available for many other phases of energy development, but in situ oil shale development presumably would be safer than "conventional" oil shale development as fewer workers per Btu produced are exposed to the hazards of mining.

(2) Chronic Health Risks

The principal chronic occupational health risks considered in this study were respiratory diseases and cancer. Data are not available that link energy development technologies with other health problems such as psychological disturbances, or circulatory or endocrine disorders.

The best known and best documented occupational health risks are respiratory disorders (black lung disease) in underground coal miners and lung cancer (from radiation exposure) in underground uranium miners. Black lung disease affects more than one-third of underground coal miners and lung cancer was reported in one out of 23 uranium miners from 1950-1973. Recent exposure standards are expected to reduce both of these risks.

TABLE 3-36: SAFETY RISKS ASSOCIATED WITH ENERGY FACILITIES EXPRESSED PER INDIVIDUAL

FACILITY	FREQUENCY PER WORKER PER YEAR	
	DEATH	INJURY
Coal		
Surface mining (12 MMtpy)	0.0011	0.034
Underground mining (12 MMtpy)	0.0024	0.090
Gasification (250 MMscfd)	0.0008	0.002
Liquefaction (30,000 bbl/day)	0.0004	0.007
Power plant (3,000 MWe)	0.0017	0.007
Oil (100,000 bbl/day)	0.0002	0.021
Gas (250 MMcfd)	0.0003	0.024
Oil Shale		
Underground mine (66,000 tpd crushed shale)	0.0014	0.062
Surface retorting	0.0004	0.045
Uranium		
Mill (1,200 tpy)	0.0003	0.104

MMtpy = million tons per year
MMscfd = million standard cubic feet per day
bbl/day = barrels per day
MWe = megawatt-electric
MMcfd = million cubic feet per day
tpd = tons per day
tpy = tons per year

Although the raw materials for coal conversion and oil generally contain very small quantities of carcinogenic substances, the processes of gasification and liquefaction result in the formation of substances which have been demonstrated to cause cancer. Although data for coal synthetic fuel technologies are not available due to the newness of the technology, workers in similar environments (e.g., oil refineries and coke plants) have shown a higher incidence of cancer.

Exposure to free silica in underground oil shale mines may cause silicosis (a lung disease), and like other synthetic fuel technologies, retorting processes produce a variety of carcinogens.

3.6.3 Variations in Existing Conditions

Several existing conditions are important to the public and occupational health impacts of energy development. For public health, these variables include composition of resources, population characteristics, terrain and atmospheric conditions, and existing health care delivery systems. For occupational health, variables primarily include the characteristics and composition of the resource and safety practices and regulations.

A. Composition of Resources

Quantities of trace elements in coals vary greatly over the eight-state region and even within a given locality. For example, coal in the Gillette region contains mercury in amounts ranging from 0.06 to 0.28 parts per million (ppm) (Chapter 7), and Kaiparowits coal contains 0.05-1.2 ppm mercury. The high concentrations of mercury in Kaiparowits coal are of particular concern since the contamination of some species of fish by mercury in nearby Lake Powell already constitutes a health hazard. The lead content of Gillette coals (1.5-40 ppm) is two to three times higher than that of the Northern Great Plains lignites.

Other resource characteristics related to health include seam thickness, major element composition (e.g., sulfur) and amount of radioactivity. Sulfur content was discussed earlier in air impacts. Seam thickness is related primarily to the extent of occupational health risk per Btu produced. For example, thinner seams in the Southwest (including underground mines in Utah and Colorado) make occupation risk greater (on a Btu basis) than mining thick seams in the Fort Union Formation in Montana and Wyoming.

The amount of radioactivity in a resource is important as a public and occupational risk primarily for uranium development. In this case, the higher the quality of the resource, the less the risks of mining on a per Btu produced basis. Although the level of radioactivity varies considerably for other resources (such as coals), as indicated previously the levels do not appear to represent a significant health risk.

B. Population Characteristics

Populations especially susceptible to health problems include the aged, infants, women of childbearing age, and people suffering from pulmonary or cardiovascular deficiencies. For example, children are more susceptible to respiratory ailments, caused by high concentrations of SO_2 and NO_x. Older people have a higher risk of heart and lung disease aggravation due to sulfate aerosols than younger members of the population. For example, generally the Northern Great Plains has the largest percentage of the population over 65 (over 10.6 percent in North and South Dakota). New Mexico and Utah have the youngest populations with less than 7.5 percent of the population over 65.

C. Terrain and Atmospheric Conditions

Terrain, temperature, and humidity all can contribute to the concentration of air pollutants. Rough terrain traps pollutants during atmospheric inversions, and the effect of the SO_2/particulate mix appears to be most pronounced when prolonged periods of moderately cold temperatures (around 30°F) and high relative humidities (above 70 percent) occur simultaneously. All these conditions occur in the winter in western Colorado; thus, other factors being equal this area would be more likely than other areas to experience high levels of pollution concentration and the consequent health problems as a result of energy resource development.

D. Existing Health Care Delivery Systems

As indicated in Section 3.4, rural areas and communities impacted by energy resource development frequently lack the infrastructure to support health care facilities and attract physicians. These problems will be especially acute for energy development in remote areas and in areas that experience rapid population growth. Particular problems with health care delivery exist in the rural Southwest such as southern Utah, northern Arizona, and northwestern New Mexico. Some disease problems may be increased unless community health services are improved.

E. Safety Practices and Regulations

Worker practices and the design and operation of the work environment are a critical factor affecting both acute and chronic worker disabilities. Although specific comparative data are not available, the practices of different companies and the safety standards enforcement programs of states and the federal government are related to variations in accident occurrences. Accidents in underground coal mines have been significantly reduced with the passage of coal mine safety acts, including the Mine Health and Safety Act of 1969. Practices and regulations on working conditions in coal mines have also apparently affected the incidence of black lung disease. Changes in accepted exposure levels to radon gas are likely to reduce the incidence of lung cancer in underground uranium miners.

3.6.4 Summary of Technological and Locational Factors

Technological and locational factors that can result in health problems are summarized in Table 3-37. Respiratory disease is a threat as a result of the SO_2, particulate, and NO_x emissions from conversion facilities, especially electric power plants. Sulfate concentrations approach those causing disease at a three to five percent SO_2-to-sulfates conversion rate and can be expected to increase the incidence of disease, especially in the aged, infants, and persons with pulmonary and cardiovascular deficiencies.

Locating labor-intensive conversion facilities in rural areas, such as the Southwest, will result in population increases that exceed the capacity of health care delivery systems. This can have a variety of adverse health implications unrelated to the emissions from energy facilities.

Emissions of trace materials from various energy facilities could have long-term, chronic effects although the seriousness is highly uncertain. For example, burning coal with a high mercury content in the vicinity of aquatic ecosystems with sport fish may increase the mercury content of fish. Mercury concentrations in some biota in Lake Powell in the vicinity of Kaiparowits, Utah, currently exceed Food and Drug Administration standards. The incremental addition from the combustion of coal in the area would aggravate this problem.

Occupational health hazards in western underground coal mines, while similar in all underground coal mines regardless of location, is a significant occupational hazard. Mortality as a result of accidents and respiratory disorders as a result of particulate inhalation can constitute significant health problems. Exposure to radiation in underground uranium mines is also a serious problem. Recent improvements in the regulations and standards affecting these working environments have substantially reduced, but not eliminated, the risks.

TABLE 3-37: SUMMARY OF TECHNOLOGICAL AND LOCATIONAL FACTORS AFFECTING HEALTH PROBLEMS

HEALTH EFFECTS PROBLEMS	COMBINATIONS OF FACTORS THAT CAUSE THE PROBLEM	
	TECHNOLOGICAL	LOCATIONAL
Respiratory disease	Energy conversion facilities, especially power plants	Population characteristics and extent of urban growth
Inadequate health care delivery system	Labor intensity of energy facilities	Rural areas, most notably in the Southwest
Potential long-term effects of trace materials	Energy conversion facilities	Trace element content of various coals
Occupational safety risks	Energy extraction and conversion technologies, especially underground mining	Coal seam thickness
Exposure to carcinogens	Synthetic fuel facilities and uranium mining and milling	Composition of the coal and worker exposure safeguards

3.7 TRANSPORTATION

HIGHLIGHTS

- ## CRITICAL FACTORS

  - Three technological factors can affect transportation impacts: capital intensity, water requirements, and the unique set of residuals characteristic of each mode.
  - Two locational factors can affect these impacts: the location and capacity of existing transportation systems, and the availability of water.

- ## CAPITAL AND OPERATING COSTS

  - Rail systems are less capital intensive than slurry systems, but both systems require large investments.
  - A higher proportion of the costs of a rail system are operation costs.
  - Direct current (DC) transmission is relatively more economical than alternating current (AC) for large volumes and long distances; AC is more economical for smaller volumes and shorter distances and when the power is routed to several destinations.

- ## FLEXIBILITY

  - Rail systems are more flexible than slurry systems in terms of fluctuating demands, delivery to numerous destinations, and transport of commodities other than coal.

- ## WATER REQUIREMENTS

  - Approximately 740 acre-ft of water are required for each 1 million tons of coal transported by slurry pipeline.
  - By the year 2000, scenario slurry pipelines originating in the Northern Great Plains could require more than 300 thousand acre-ft/yr or 23 percent of the water used for energy development in that area.

- ## EXISTING CAPACITY

  - Existing gas pipelines in the Four Corners area are expected to be adequate to transport both natural and synthetic gas through the year 2000; additional oil pipeline capacity will be needed even in the Low Demand scenario.

- *Existing oil pipelines in the Northern Great Plains are expected to be adequate to transport both crude and syncrude through the year 2000; additional gas pipelines will be needed in the area.*
- *New transmission lines will be required for almost all new electric power plants built in the region.*

3.7.1 Introduction

This study verifies what has been found in a number of previous studies: that large-scale resource development in the western U.S. will require substantial new investments in transportation facilities. As discussed in Chapter 11, capital costs for transportation may involve more than $30 billion by the end of the century, equivalent to more than 25 percent of the total cost of the energy facilities.[1] In addition to the impacts this investment will have on the national economy, transportation facilities can produce locally significant environmental impacts along their rights-of-way. These impacts include noise, accidents, visual intrusion, and barriers to human and animal mobility. Factors that determine the extent of such impacts are summarized below.

3.7.2 Variations Among Technologies

Choices among transportation modes are limited by the choices among energy conversion technologies. The first choice to be made is whether to convert the resource at or near the mine site (the "mine-mouth" option) or ship it to the demand centers in raw form (the "strip and ship" option). If the mine-mouth option is chosen, several final fuel forms are available (liquids, gases, and electricity), each with specific transportation modes available. If strip and ship is chosen, the two primary options are rail and slurry pipeline. The present discussion is organized around the choice of mode, since each has certain characteristic impacts.[2]

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[1] See also the policy analysis of energy transportation, in White, Irvin L., et al. Energy From the West: Policy Analysis Report. Washington, D.C.: U.S., Environmental Protection Agency, forthcoming, Chapter 11.

[2] As part of this study, the Center for Advanced Computation at the University of Illinois at Urbana-Champaign undertook a cost comparison study of alternate transportation options under a subcontract with the University of Oklahoma. See Rieber, Michael, and Shao Lee Soo. "Route Specific Cost Comparisons: Unit Trains, Coal Slurry Pipelines and Extra High Voltage Transmissions," Appendix B in White, Irvin L., et al. Energy From the West: A Progress Report of a Technology Assessment of Western Energy Resource Development. Washington, D.C.: U.S., Environmental Protection Agency, 1977.

A. Export of Solids: Rail versus Slurry

We have examined two types of solid fuels: coal and uranium.[1] Since substantially larger amounts of coal production are anticipated (in terms of weight), attention has been focused on that resource. Of the two leading prospects for coal transport, rail and slurry pipeline, it is generally believed that slurry pipelines are more economical when transporting large volumes over long distances.

More than 90 percent of the total cost of a slurry system is capital-related, while operating costs form a higher proportion for a rail system.[2] This large capital-operating cost imbalance means that slurry pipelines are economical alternatives to rail systems only when their capacities can be fully used. Consequently, slurry pipeline operations need firm, long-term contracts and throughput rates close to design specifications to operate economically and efficiently.

The water required by slurry lines (740 acre-ft per million tons of coal) will make additional demands on already short supplies in some regions of the West. Although closed-loop systems (where the water is returned in another pipeline) and the use of petroleum products instead of water have been discussed,[3] neither is considered an economically viable alternative at present. Slurry pipelines avoid a number of the environmental impacts of rail systems. Railroads are noisy, disrupt vehicular traffic in urban areas, and create a safety hazard at grade crossings.

Rail systems are more flexible than slurry pipelines in their ability to meet fluctuating demand levels and in their potential to deliver to a variety of geographic locations. Moreover, rail lines can carry other kinds of freight when not used to capacity by unit coal trains.

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[1] Although oil shale may be mined as a solid, export of the shale before extracting the kerogen is not considered practical because of the large volume of shale that would have to be transported.

[2] The comparative economics of the two systems depend, to a great extent, on the cost of restoring existing rail lines. This cost is discussed later in this section.

[3] The petroleum product would be burned, along with the coal, in this alternative. To the best of our knowledge, no one has seriously proposed a closed-loop system.

At the railroad usage levels anticipated in the regional scenario,[1] noise impacts will be substantial for many people. More than one million people live within one mile of one Montana-to-Chicago route, a range within which noise produced by a single unit train can be annoying. In the case of traffic disruption, the rail usage anticipated could amount to 43 round trips per day to the Chicago area. If just half of this traffic (i.e., 22 round trips per day) is sent along a single rail line at 20 miles per hour (mph), the chance of a grade crossing being blocked at any given time will be approximately one in ten. Towns with over- or underpasses, of course, will not suffer this impact (nor the noise of train horns).

Environmental impacts of slurry pipelines are different in kind and are almost entirely related to their use of water. The water must be treated at the end of the line before being reused or discharged. One of the products of this treatment, which must be disposed of, is a sludge of coal fines containing as much as five percent of the original coal. Also, spills can occur as a result of failures in pipes or pumping station equipment. With the exception of pumping stations, repairing such leaks will normally require flushing a substantial portion of the line and thus discharging a large amount of the slurry into a holding pond. This coal slurry cannot be reinjected into the line.

Physical input requirements of the two systems will be roughly comparable on a region-wide basis. For example, railroads would use 9.5 million tons of steel by the year 2000 under the Nominal Demand scenario, versus 7.8 million tons for slurry pipelines. Each system requires about 380 tons of steel per mile for fixed structures (assuming 25 million tons/year capacity), but railroads will also need rolling stock. On the other hand, many of the railroad lines are already in place and will simply require some upgrading.

B. Export of Electricity: AC versus DC

Electrical transmission avoids many of the problems mentioned above and, in some ways, constitutes even less of a barrier to animals than do above-ground pipelines. Like slurry pipelines, electrical transmission costs are heavily weighted toward initial capital investments, and the economics of such lines are predicted on high utilization of capacity. The concept of mine-mouth electrical generation for export implies that there are almost never any existing transmission facilities.

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[1] More than one hundred 100-car unit trains leaving the Powder River Basin daily by the year 2000.

Because of their height, transmission lines have more of an aesthetic impact than do other transport modes. Additionally, there is the possibility of impacts from ozone generated by high voltage transmission.

The two major technological alternatives available for electrical transmission are AC and DC. AC has relative advantages when smaller quantities of power are sent over shorter distances (as compared to DC applications). AC also allows more flexibility in terms of delivering power to many destinations simultaneously. These differences arise mainly from the fact that DC terminal installations are more complex and expensive. In other respects, DC seems to have the advantage: they can carry significantly higher line loads, have lower transmission losses, result in less noise, and require shorter supporting towers. Still, the voltages being contemplated for bulk energy transmission (800 kilovolts) produce unique phenomena (e.g., some electrostatic effects) with which little operating experience has yet been gained.

C. Gas and Liquid Pipelines

Pipelines will be used when petroleum and natural gas are exported from the region in raw form, or when coal is liquefied or gasified within the region. Oil and gas pipelines create few adverse impacts although high-pressure gas pipelines are a significant safety hazard.

3.7.3 Variations Among Existing Conditions

Certain locational characteristics partly determine the impacts of energy transportation systems. The key variations are the capacity of existing transport links in close proximity to developable energy deposits, and, in the case of slurry pipelines, the extent of available water resources.

A. Existing Capacity of Transport Links

Obviously, extraction (and, to some extent, processing) must be done wherever the minerals are found. More often than not in the West, the deposits are located far from established population centers and their associated transportation networks. The following discussion summarizes present capacity by area for rail systems, gas and oil pipelines, and electrical transmission lines. At present there is only one major slurry pipeline in the region, the Black Mesa line in Arizona and Nevada.

(1) Rail Systems

In the eight-state study area, rail facilities are especially sparse around the Four Corners area. In that region, the distance from coal deposits to the nearest rail trunk line may often exceed 150 road miles. Due to denser populations and greater agricultural production, rail links in the Great Plains have been developed more extensively.

The capacity and quality of rail lines presents the most problematic issue concerning the study area's transportation system. Comprehensive, systematic data are not available on how much coal could be carried over the current rail lines or how capacity varies by region. However, much of the nation's rail lines have not been maintained to normal standards, and unit trains will require better-than-standard track for high-speed operation. One estimate of reconstruction costs is $3.3 billion (1973 dollars).[1]

However, even if all existing lines are upgraded for unit trains, the volumes of coal in the regional scenario will necessitate the building of new main lines. There is some disagreement as to when existing rail line saturation would occur, but assuming that 70 million tons of coal per year could be handled on one set of double track, some 6,600 miles of additional track would be required by 2000, at a cost of $2.0 billion. However, any excess carrying capacity of new and rebuilt rail lines would be available for other commodity shipments, which is an advantage not shared by slurry pipelines, the other coal transport mode considered here.

(2) Transmission Lines

Generally speaking, each mine-mouth power plant will need a new transmission line to connect it with the distribution network at the load center. Substantial transmission capacity links the Four Corners area, Arizona, and Los Angeles; other routes are less developed.[2] The Nominal Demand scenario would call for 13,000 new miles of electric lines, each capable of carrying 2,200 MWe, in the region by the year 2000.

(3) Gas and Oil Pipelines

Existing gas pipeline capacity from the Four Corners states is adequate through the year 2000 for the synthetic gas and natural gas developments projected in both the Nominal Demand and Low

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[1] U.S., Federal Energy Administration. Project Independence Blueprint, Final Task Force Report: Analysis of Requirements and Constraints on the Transport of Energy Materials, Vol. I. Washington, D.C.: Government Printing Office, 1974.

[2] Energy Resources Co. Preliminary Assessment of the Economic and Environmental Impact of Alternative Demand/Supply Scenarios for Electricity in the Southwest. Draft Final Report, for U.S. Environmental Protection Agency. Cambridge, Mass.: Energy Resources Co., 1976.

Demand scenarios. Two major interstate gas pipeline companies have pipelines that currently traverse the area; these have a total yearly capacity of 2,341 billion cubic feet (bcf), exclusive of added compression and looping which could be used to increase the capacity. Except for short pipelines to tie in with these existing trunk lines, no new pipelines should be required. In the Northern Great Plains, gas pipeline capacity will probably not be adequate. A Nominal Demand scenario projects that 201 bcf of gas in 1990 and 3,429 bcf in 2000 will be produced in the Powder River Coal Region. One major gas pipeline with a capacity of 56 bcf per year currently traverses the Powder River Region.

Existing oil pipeline capacity is adequate in the Northern Great Plains and inadequate in the Four Corners states. Assuming the Nominal Case level of development, 142 thousand bbl/day is projected to be produced in the year 2000 in the Powder River area of the Northern Great Plains. Existing capacity there is 620 thousand bbl/day. In the Four Corners area, 3.9 million bbl/day should be produced by 2000, and existing capacity without looping is 260 thousand bbl/day.

B. Water Availability for Slurry Pipelines

The viability of a slurry pipeline depends on the availability of water at the shipping point. In general, more water is available from the UMRB than from the UCRB. However, the amount of water available from specific areas depends on technical, economic, and legal factors. For example, slurry pipelines may be able to utilize groundwater sources which, because of cost or low water quality, other water users would not consider. Water availability also depends on state law and interstate compacts which restrict the diversion of water outside a river basin. Ironically, these may prevent slurry pipeline development while allowing generation of electricity for export from the region, even though electric generation consumes more water per unit of coal input than do slurry pipelines.

3.8 AESTHETICS AND NOISE

HIGHLIGHTS

- **AESTHETICS**

  - *The most critical aesthetic impacts from energy development are likely to occur near national parks, forests, monuments, isolated areas, and areas in a natural state. These areas are highly valued in the West and aesthetic impacts can quickly detract from their beauty or value.*

- *Strip mines, conversion plants, transmission lines, and trains will produce visual intrusions, opaque plumes, and reductions in visibility.*

- *Strip mining often results in the most severe short-term aesthetic impacts on land; thus, the success of reclamation practices will be critical in determining the magnitude of aesthetic impacts.*

- **NOISE**

  - *Noise impacts will be significant within one-half mile of rail lines, where the noise level will be above 55 decibels. Depending on the route, these impacts could affect a large number of people.*

3.8.1 Introduction

Aesthetic impacts from energy development include alterations in the land, air, water, and biota, and increases in noise levels. Personal values will be important in determining how critical these impacts will be. Aesthetic impacts from energy development will be discussed as they vary by technology and then as they vary by existing conditions.

3.8.2 Variations by Technologies

A. Aesthetics

In general, western residents highly value the natural beauty and, in many areas, the scenically spectacular nature of their region. Thus, many westerners perceive strip mines, energy conversion facilities, stacks, plumes, transmission lines, etc., more negatively than do newcomers who are employed by the energy development activities. While few data exist to evaluate systematically the aesthetic impacts of different energy development technologies, several generalizations about potential impacts can be made. For example, the most serious land-related impacts result from surface strip mining which can alter the vegetation, color, and topographic character of the land. Thus, how much land is disturbed and how successful reclamation is will be critical from an aesthetic viewpoint.

Aesthetic impacts on air are likely no matter where conversion facilities are located in the West since so much of the West enjoys long and clear visibility. Emissions from energy facilities, particularly power plants, will reduce visibility by an average of eight percent. During worst-case weather conditions, visibility can be reduced by as much as 80 percent. Air pollutants can also alter the natural coloration of the sky in some areas, thus affecting the contrast of natural features and formations against the skyline.[1] Air pollutant emissions (e.g., hydrogen sulfide, SO_2, and various HC) can also produce unpleasant odors close to facilities.

The appearance and rate of movement of water are also valued aesthetic qualities. Direct water consumption for energy development will decrease flow rates, increase turbidity, expose previously submerged areas, and cause discoloration of shorelines due to algae growth. In addition, increases in the local population will probably result in greater quantities of materials being discarded in streams, a very apparent aesthetic impact.

The density of human-made objects and other evidence of human presence is aesthetically objectionable to some people. Over 100 new large-scale energy conversion facilities are projected for the West in the Low Demand case by the year 2000. Skyline alteration (e.g., smokestacks and transmission lines) from these facilities will be another impact because of the long distance from which a structure on the skyline can be observed. The color, design and location of a facility may also affect its aesthetic appeal.

B. Noise

Noise is often considered an aesthetic impact; however, it is also becoming recognized as a pollutant which may affect public health. Energy development in each of the scenarios will increase levels of traffic (highway and rail) and will introduce new stationary sources of noise as well (mining, and construction and operation of facilities). The amount of noise generated will depend on the particular types of equipment used, and on the presence or absence of physical noise barriers.

Among stationary sources, surface strip mining will have less impact on the noise levels than power plant construction and operation. This is in part due to the tall overburden piles which reduce some of the mining noise. Haulers will be the principal noise source of the strip mines, and will cause annoyance levels up to one-half mile from the mine. The construction and operation of energy conversion facilities will cause annoyance levels up to one mile from the plant.

Among transportation sources, trucks and unit train engines produce noise levels which result in an annoyance level within one-half mile of roads and railroad lines. Moving sources, such as coal trains, will generally produce more extensive impacts than stationary sources because they affect more people. In addition, there are few tall buildings along railways to block the noise.

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[1] U.S., Department of the Interior, Bureau of Land Management. Final Environmental Statement: Proposed Kaiparowits Project, 6 vols. Salt Lake City, Utah: Bureau of Land Management, 1976, Chapters III-VII.

3.8.3 Variations by Existing Conditions

A. Aesthetics

Aesthetic land impacts will vary according to the existing topographic, climatic, and biological conditions at the facility site. Although federal law[1] requires reclamation of surface-mined land to the original vegetation and contour, the success of reclamation will depend critically on rainfall and how much water is available for irrigation. Thus, the potential success of reclamation is very uncertain in many western areas, but particularly in the arid Southwest. If reclamation does succeed, the aesthetic quality of an area can be improved if distinctive new relief characteristics are added or, in some cases, if "non-native" vegetation would be allowed.

Air-related aesthetic impacts will be aggravated by the rugged terrain of some areas. This is especially true in western Colorado and southern Utah. Loss of visibility will also be perceived most readily in areas of Utah and Arizona where long distance visibility has come to be expected by residents and tourist.

Where new access roads make wilderness areas more accessible, increases in ORV use could destroy plant life and encourage illegal activities such as poaching or indiscriminant killing of non-game animals. This is a potential problem at all energy development sites in the West, but negative impacts are most likely around Beulah, North Dakota, where the geologic fragility and high recreational potential of the badlands to the west make them extremely vulnerable to overuse; Escalante, Utah, which is surrounded by national parks, forests, and recreation areas, all within easy driving distances from hypothesized energy facilities; and Rifle, Colorado, which is close to several national parks and forests and where certain heavily used areas are already beginning to show signs of deterioration.[2]

The aesthetic visual impact of the facilities may be reduced if they are designed to conform to the surroundings. This is expected to be most difficult in the Northern Great Plains due to flat topography.

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[1] Surface Mining Control and Reclamation Act of 1977, Pub. L. 95-87, 91 Stat. 445.

[2] Todd, J. "We're Losing the Wild in the Wilderness." Colorado Outdoors, Vol. 25 (March/April 1976), pp. 10-11.

B. Noise

Noise impacts will depend primarily on the distances between sources and populations. Thus, people living closest to energy facilities will experience the highest average sound levels. As noted, railroads will affect the greatest numbers of people. For example, more than one million people live within one mile of a railway main line from Montana to Chicago. The distribution of mining and facility noise impacts will depend almost entirely on the distribution of energy development in the West. In addition, topography and foliage will modify noise impacts to a degree. For example, valleys tend to entrap noises generated within them, and dense brush and forests absorb sound waves quickly.

3.8.4 Summary of Technological and Locational Factors

The blue skies and long-range visibility of the western states are highly valued, both for their intrinsic appeal and for their enhancement of the scenic beauty of parks, monuments, and projected sites in the region. Many portions of the study area have average visibilities of 65-70 miles, and some places in southern Utah and northern Arizona allow clear visibility up to 100 miles. Thus, any reduction in long-range visibility at particular sites will probably be considered a negative aesthetic impact by both residents and tourists.

In spite of revegetation requirements, the changed appearance of mining areas may be a negative impact to some people simply because it is different from what existed "naturally." Problems in reclaiming mined land may reduce the variety of vegetation in some more arid areas of the West, thus contributing to the disappearance of certain wildlife species. Similarly, the dewatering of aquifers and the infiltration of aquifers, springs, and streams by waste pond leachates could harm aquatic species and wildlife that use these water sources. These potential ecological problems could degrade the wildlife and vegetation in national parks and pristine places. Thus, reduction or loss of wildlife and vegetation in some areas will have negative aesthetic impacts on area visitors.

As noted previously, energy development-related noise increases from both stationary and moving sources cause aesthetic impacts in nearby communities. To some long-time residents, both the intermittent and continuous sounds will be displeasing, annoying, and possibly disturbing to typical patterns of behavior and sleep. In an area such as Rifle, Colorado, where a larger than normal fraction of the population is of retirement age, the noise created by an energy development could be especially annoying. The fact that retirement-age people have moved into this area seems to indicate a desire to get away from the disturbing effects of higher-paced life elsewhere and spend their retirement years in relatively calm, quiet surroundings.

3.9 SUMMARY

This section summarizes differences in impacts that can be expected from different combinations of technological and locational factors and the general trade-offs between exportation and on-site conversion of coal resources.

3.9.1 Technological and Locational Factors That Cause Impacts

Table 3-38 lists the most significant impact-causing factors identified in Sections 3.2-3.8. Among technological factors, labor intensity contributes to several impacts: air quality; water use; water quality; the ability of communities to provide facilities and services; the extent of political disruptions caused by changes in the relative number of newcomers; and the extent to which plant communities and wildlife habitat will be disrupted. The severity of environmental impacts will depend largely on the choice of energy technology and the extent to which environmental control technologies are employed. If air emission controls, water-saving cooling options, and wastewater control technologies are employed, the adverse impacts on terrestrial and aquatic ecosystems, human health, and aesthetic characteristics (such as visibility) can be reduced but not eliminated.

Community size is among the most important locational factors, contributing to: water quality problems in small communities which often do not have adequate sewage treatment plants nor the resources for expanding them; inadequate services since the institutional and financial capacity to expand services is often lacking in small communities; the extent of political disruptions caused by changes in the newcomer-to-oldtimer ratio; and health care capacity.

Coal characteristics, which vary widely in the eight-state area, affect: air quality (as sulfur and ash content vary); water use (as moisture and seam thickness vary); water quality (as effluent streams vary in composition in accordance to variations in coal composition); the extent to which plant communities and wildlife habitat are degraded and eliminated (as seam thickness and thus land use vary); and health impacts (as the trace element composition, sulfur, and ash content vary).

3.9.2 Export versus On-site Conversion

Two major locational choices are available as regards coal conversion facilities: ship the coal out of the region to be

TABLE 3-38: IMPACT CAUSING FACTORS

IMPACT CATEGORY	TECHNOLOGICAL FACTORS	LOCATIONAL FACTORS
Air	Quantities of emissions Efficiency of pollution control systems Labor intensity	Coal characteristics Terrain and dispersion potential Community size and location Ambient air quality and emissions standards
Water	Process water requirements Type of cooling system Labor intensity Amounts of liquid and solid wastes Aquifer disruption	Water availability Coal characteristics Ambient water quality Aquifer characteristics Sewage treatment capacity of the community
Social/Economic	Labor intensity Scheduling Capital intensity	Community size and location Capabilities of existing institutions Historical out-migration Characteristics of local labor force Local financial conditions Culture and lifestyle of an area
Ecology	Land use Labor intensity Water requirements Water effluents Air emissions	Ecosystem stability and resiliency Climate Plant and animal communities Character of existing land-use patterns
Health	"Criteria" pollutants Trace materials Working conditions Type of transportation system	Coal characteristics Population characteristics Terrain Existing health care delivery systems
Aesthetics and Noise	Visibility reduction Land use Noise level and pattern	Local attitudes Topography Existing regulatory and enforcement problems Accessibility to wilderness areas

converted elsewhere, or mine and convert the coal to another fuel form on-site, in which case the choice is among the types of conversion technologies. This section briefly summarizes some of the consequences of those choices and how locational factors can affect them.

A. Coal Export

Mining and exporting western coal will substantially reduce the negative air quality, water, ecological, social, political, and health impacts for the region. Air emissions from mining are primarily blowing dust and can be negligible if proper dust suppression techniques are used; and emissions from urban sources associated with mining are much less (because population increases are less) than is the case with conversion facilities. Even when intensive irrigation is assumed, water use for reclamation is one-tenth that required by a conversion facility. In either the export or mine-mouth conversion case, degradation and elimination of terrestrial plant and wildlife communities will result from surface mining, but population-induced ecological impacts associated with labor intensive coal conversion facilities will be avoided if resources are exported. Because mining has low labor requirements, fewer social and political impacts, resulting from inadequate services and facilities and the influx of newcomers, are expected. Since air and water quality remain virtually unchanged, public health hazards are minimal. Occupational risks with mining remain in both cases. This is not to say that mining does not have negative impacts. For example, aquifer systems can be altered and underground miners will be exposed to occupational health hazards. The negative impacts from coal transportation (primarily safety risks, noise, and community disruption from unit trains and water consumption of slurry pipelines) will be magnified with the export option.

Mining for export may also minimize many of the positive impacts. Tax revenues, employment potential, and income benefits associated with capital- and labor-intensive conversion facilities are exported along with the coal.

B. Mine-Mouth Conversion

Facilities for producing synthetic fuels from coal have many impact-causing factors in common, and these factors are substantially different from those associated with electric power plants. Synthetic fuels facilities result in fewer air quality problems than electric power generation because emissions are considerably less (HC emissions from coal liquefaction and oil shale retorting facilities are an exception). The hypothetical coal synthetic fuels facilities at our sites do not cause federal ambient air standards (except for HC) or Class II PSD increments to be exceeded. Power plants in our scenarios regularly violate Class II increments even when high levels of pollutant removal by air emission control technologies are assumed. If control technologies were lower (at levels which would meet NSPS), then ambient standards would be violated.

Similarly, water use by electric power plants is considerably higher than that of synthetic fuels facilities (unless power plants use intermediate or minimum wet cooling, in which case they are similar). A typical size Lurgi gasification facility requires less water than other typical-size conversion technologies. In the central Rocky Mountains and Southwest, water consumption may be the determining variable in choosing a conversion technology. Since air quality is also more of a problem in these areas (due to the terrain, dispersion potential, and, in the case of Colorado, state ambient air quality standards), synthetic fuels facilities may be a more desirable choice for the Southwest and central Rocky Mountains than power plants. If electric power plants are sited in these two areas, air emission control technologies may require very high removal efficiencies and water saving cooling options may have to be employed.

Although all conversion technologies are more labor intensive than mining, typical size synthetic fuels facilities are more labor intensive than typical size electric power plants. This means that the social, economic, political, and ecological impacts of electric power plants will be somewhat less than those of synthetic fuels facilities. Electric power plants also offer larger increases in the tax base than do synthetic fuel facilities.

C. The Effect of Locational Considerations

The effects of conditions at a specific site cut across all the generalizations stated above either to worsen or mitigate impacts. Those conditions that affect air quality, water, and ecological impacts generally vary according to three subareas in the eight-state study area: Northern Great Plains, Rocky Mountains, and Southwest. However, social, economic, and political impacts are also sensitive to other factors. As mentioned above, community size is a critical locational variable, affecting the capacity of the public and private sectors to provide services, the nature of the local labor force, and the extent to which oldtimers are likely to be displaced by newcomers in the political power structure. State impact mitigation programs also determine a community's ability to respond to rapidly escalated demands for services and facilities, and such programs vary from state to state.

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